YEAR 2001

ANNUAL REPORT
OF

Montana-Dakota Utilities Company

GAS UTILITY

TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

Gas Annual Report

Instructions

General

1. A Microsoft EXCEL 97 workbook of the annual report is being provided on computer disk for your convenience. The workbook contains the schedules of the annual report. Each schedule is on the worksheet named that schedule. For example, Schedule 1 is on the sheet titled "Schedule 1". By entering your company name in the cell named "Company" of the first worksheet, the spreadsheet will put your company name on all the worksheets in the workbook. The same is true for inputting the year of the report in the cell named "YEAR". You can "GOTO" the proper cell by using the F5 key and selecting the name of the cell.

2. The workbook contains input sections that are unprotected, and non-input sections that are protected. Cell protection can be disabled or enabled through "TOOLS – PROTECTION – UNPROTECT SHEET" on your toolbar. Formulas and checks are built into most of the templates.

3. Use of the disk is optional. The disk and the report cover shall be returned when the report is filed. There are macros built into the workbook to assist you with the report. An explanation of the macros is on the "Control" worksheet at the front of the workbook. The explanations start at cell A1.

4. All forms must be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report shall be filed. **Please submit one unbound copy of the annual report along with the regular number of annual reports that you submit.** This aids in scanning the report so that it may be published on our web site. The orientation and margins are set up on each individual worksheet and should print on one page. If you elect not to use the disk, please format your reports to fit on one 8.5'' by 11'' page with the left binding edge (top if landscaped) set at .85'', the right edge (bottom if landscaped) set at .4'', and the remaining two margins at .5''. You may select specific schedules to print – See the worksheet "CONTROL".

5. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ( ).

6. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.

7. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).

8. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.

9. All companies owned by another company shall attach a corporate structure chart of the holding company.

10. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

11. The following schedules shall be filled out with information on a total company basis:

    Schedules 1 through 5
    Schedules 6 and 7
    Schedule 14
    Schedule 17 and 18
    Schedules 23 through 26
    Schedule 33

    All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

    Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

12. For schedules where information may be provided using Mcf or Dkt, circle Mcf or Dkt to indicate which measurement is being reported. (For example, schedules 28, 32, 33 and 34).

13. FERC Form-2 sheets may not be substituted in lieu of completing annual report schedules.

14. Common sense must be used when filling out all schedules.

Specific Instructions

Schedules 6 and 7

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 201 shall be used.

2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.

3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

Schedules 8, 18, and 23

1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 8A, etc.).

Schedule 12

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was $5,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall report aggregate payments of $25,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall report aggregate payments of $75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

Schedule 14

1. Companies with more than one plan (for example, both a retirement plan and a deferred savings plan) shall complete a schedule for each plan.

2. Companies with defined benefit plans must complete the entire form using FASB 87 and132 guidelines.

3. Interest rate percentages shall be listed to two decimal places.

Schedule 15

1. All changes in the employee benefit plans shall be explained in a narrative on lines 15 and 16. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 15 and 16. All assumptions used in quantifying cost containment results shall be disclosed.

2. Schedule 15 shall be filled out using FASB 106 and 132 guidelines.

Schedule 16

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

Schedule 17

1. Respondents shall provide all executive compensation information in conformance with that required by the Securities and Exchange Commission (SEC) (Regulation S-K Item 402, Executive Compensation).

2. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

3. All items included in the "other" compensation column shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

4. In addition, respondents shall attach a copy of the executive compensation information provided to the SEC.

Schedule 24

1. Interest expense and debt issuance expense shall be included in the annual net cost column.

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)

2. The retention and price/earnings ratios shall be calculated on a year end basis. Enter the actual year end market price in the "TOTAL Year End" row. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 27

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.

2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.

2. Indicate, for each adjustment on lines 28 through 46, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 28

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

Schedule 31

1. This schedule shall be completed for the year following the reporting year.

2. Respondents shall itemize projects of $50,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall itemize projects of $100,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall itemize projects of $1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

Schedule 34

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.

2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

Gas Annual Report

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IDENTIFICATION

Year: 2001

1.	Legal Name of Respondent:	MDU Resources Group, Inc.
2.	Name Under Which Respondent Does Business:	Montana-Dakota Utilities Co.
3.	Date Utility Service First Offered in Montana	1920
4.	Address to send Correspondence Concerning Report:	Montana-Dakota Utilities Co. 400 North Fourth Street Bismarck, ND 58501
5.	Person Responsible for This Report:	Donald R. Ball
5a.	Telephone Number:	(701) 222-7630

Control Over Respondent

1. If direct control over the respondent was held by another entity at the end of year provide the following:

   1a. Name and address of the controlling organization or person:

   1b. Means by which control was held:

   1c. Percent Ownership:

SCHEDULE 2

Board of Directors 1/

Line No.	Name of Director and Address (City, State) (a)	Remuneration (b)
1	Martin A. White, Bismarck, ND	-
2	Ronald D. Tipton, Bismarck, ND	-
3	C. Wayne Fox, Bismarck, ND	-
4	Lester H. Loble II, Bismarck, ND	-
5	Bruce T. Imsdahl, Bismarck, ND	-
6	Ronald G. Skarphol, Bismarck, ND	-
7	Douglas C. Kane, Bismarck, ND	-
8	Warren L. Robinson, Bismarck, ND	
9		
10		
11	1/ Montana-Dakota Utilities Co. is a division of MDU Resources Group, Inc.,	
12	and has no Board of Directors. The affairs of the company are managed by	
13	a Managing Committee, the members of which are provided herein rather	
14	than the directors of MDU Resources Group, Inc.	
15		
16		

Officers

Year: 2001

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chief Executive Officer	Executive	Ronald D. Tipton
3	President	Executive	C. Wayne Fox
5	Executive Vice President	Business Development	Ronald G. Skarphol 1/
7	Vice President	Operations	David L. Goodin
9	Vice President	Energy Supply	Bruce T. Imsdahl
11	Vice President, Controller	Accounting and Information	Craig A. Keller
12	and Chief Accounting	Systems	
13	Officer		
15	Vice President	Human Resources	Richard D. Spratt
17	Assistant Vice President	Gas Supply	Donald F. Klempel
22	1/ Effective 3/1/2002, Dennis L. Haider assumed the title of Executive Vice President for		
23	Business Development and Strategic Planning.		

CORPORATE STRUCTURE

Year: 2001

	Subsidiary/Company Name	Line of Business	Earnings (000's)	Percent of Total
1	Montana-Dakota Utilities Co. (A Division of MDU Resources Group, Inc.)	Utility	$19,718	12.71%
5	Great Plains Natural Gas Co. (A Division of MDU Resources Group, Inc.)	Natural Gas Distribution	(324)	-0.21%
9	WBI Holdings, Inc.	Pipeline and Energy Services and Natural Gas and Oil Production	81,702	52.68%
12	Knife River Corporation	Construction Materials and Mining	43,199	27.86%
15	Utility Services, Inc.	Utility Services	12,910	8.32%
17	Centennial Holdings Capital Corp.	Domestic Growth Opportunities	(799)	-0.51%
19	MDU Resources International, Inc.	International Growth Opportunities	(1,319)	-0.85%
50	**TOTAL**		$155,087	100.00%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - GAS

Year: 2001

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$2,090	3.32%	$60,810
2						
3	Advertising	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,492	3.27%	73,792
4			Studies, and/or Actual Costs Incurred			
5						
6	Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time	6,386	1.99%	314,463
7			Studies, and/or Actual Costs Incurred			
8						
9	Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time	935	4.26%	21,023
10			Studies, and/or Actual Costs Incurred			
11						
12	Bank Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or	11,298	3.02%	363,213
13			Actual Costs Incurred			
14						
15	Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time	3,779	2.96%	124,101
16			Studies, and/or Actual Costs Incurred			
17						
18	Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	29,059	2.75%	1,028,930
19			Actual Costs Incurred			
20						
21	Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or	40,829	3.83%	1,024,849
22			Actual Costs Incurred			
23						
24	Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a	95,856	3.30%	2,808,959
25			Combination of Net Plant Investment and Number of			
26			Employees			
27						
28	Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on	5,566	3.74%	143,289
29			Number of Employees			

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 5

CORPORATE ALLOCATIONS - GAS

Year: 2001

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	3,976	3.32%	115,676
Employee Reimbursable Expenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	9,270	3.21%	279,445
Express Mail	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	98	3.58%	2,642
Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	33,655	1.67%	1,983,268
Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	41	3.29%	1,205
Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	5,310	3.35%	153,384
Moving Expense	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	42	3.28%	1,237
Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	3,940	3.84%	98,636
Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	2,916	3.32%	85,013
Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and Allocation Factors Based on Actual Experience	158,460	11.44%	1,226,170

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - GAS

Year: 2001

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	740	3.57%	20,015
2			Actual Costs Incurred			
3						
4	Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or	942	3.35%	27,211
5			Actual Costs Incurred			
6						
7	Payroll	Administrative & General	Various Corporate Overhead Allocation Factors, Time	306,169	3.34%	8,859,657
8			Studies, and/or Actual Costs Incurred			
9						
10	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or	586	5.43%	10,196
11			Actual Costs Incurred			
12						
13	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or	3,270	3.35%	94,211
14			Actual Costs Incurred			
15						
16	Seminars & Meeting	Administrative & General	Various Corporate Overhead Allocation Factors, Time	3,317	3.39%	94,438
17	Registrations		Studies, and/or Actual Costs Incurred			
18						
19	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	1,448	3.32%	42,138
20			Studies, and/or Actual Costs Incurred			
21						
22	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,883	3.32%	83,911
23			Studies, and/or Actual Costs Incurred			
24						
25	**TOTAL**			$735,353	3.70%	$19,141,882

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**KNIFE RIVER CORPORATION**	Expense	Actual Costs Incurred			
2		Air Service		$7,723		$2,505
3		Employee Training		1,158		310
4		Materials		2,900		2,900
5		Office Supplies		24,358		6,527
6		Software Maintenance		(24,361)		(6,528)
7						
8		Capital	Actual Costs Incurred			
9		Materials		11,475		
10		Software License Fees		30,589		
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23		Total Knife River Corporation Operating Revenues for the Year 2001			$806,898,922	
24						
25						
26						
27	**TOTAL**	**Grand Total Affiliate Transactions**		$53,842	0.0067%	$5,714

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**WBI HOLDINGS, INC**	Natural Gas	Actual Costs Incurred			
2		Purchases/Transportation		$58,637,821		$17,437,226
3						
4						
5						
6						
7						
8						
9		Expense	Actual Costs Incurred			
10		Contract Services		12,122		4,931
11		Legal Fees		18,403		4,931
12		Materials		1,010		1,010
13		Employee Training		3,065		847
14						
15						
16		Capital	Actual Costs Incurred			
17		Contract Services		1,479		
18		Materials		19,000		
19						
20						
21						
22		Other Transactions/Reimbursements	Actual Costs Incurred			
23		Miscellaneous		67		
24						
25						
26						
27		Total WBI Operating Revenues for the Year 2001			$680,351,745	
28						
29						
30						
31	**TOTAL**	**Grand Total Affiliate Transactions**		$58,692,967	8.6269%	$17,448,945

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**UTILITY SERVICES, INC.**	Expense				
2		Contract Services	Actual Costs Incurred	$55,034		$55,034
3						
4						
5						
6						
7		Capital				
8		Contract Services	Actual Costs Incurred	165,174		165,174
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27						
28		Total USI Operating Revenues for the Year 2001			$364,750,213	
29						
30						
31						
32	**TOTAL**	**Grand Total Affiliate Transactions**		$220,208	0.0604%	$220,208

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**CENTENNIAL HOLDINGS**	Expense	Actual Costs Incurred			
2	**CAPITAL CORP.**	Corporate Aircraft		$54,768		$16,746
3						
4						
5						
6		Capital				
7		Corporate Aircraft	Actual Costs Incurred	7,144		
8						
9						
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28						
29	**TOTAL**	**Grand Total Affiliate Transactions**		$61,912		$16,746

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$25,915		
4		Advertising	Costs Incurred	31,420		
5		Air Service		106,267		
6		Automobile		2,754		
7		Bank Services		154,298		
8		Corporate Aircraft		51,179		
9		Consultant Fees		290,233		
10		Contract Services		395,171		
11		Directors Expenses		1,197,891		
12		Employee Benefits		57,123		
13		Employee Meeting		49,297		
14		Employee Reimbursable Expense		108,378		
15		Express Mail		1,109		
16		Freight		5		
17		Legal Retainers & Fees		470,233		
18		Moving Allowance		527		
19		Meal Allowance		506		
20		Cash Donations		15,979		
21		Meal & Entertainment		51,252		
22		Industry Dues & Licenses		29,646		
23		Office Expenses		34,943		
24		Supplemental Insurance		(14,418)		
25		Permits & Filing Fees		8,455		
26		Postage		11,532		
27		Payroll		3,261,778		
28		Reference Materials		38,994		
29		Rental		2,025		
30		Seminars & Meeting Registrations		38,456		
31		Software Maintenance		17,958		
32		Training		35,759		
33		**Total MDU Resources Group, Inc.**		$6,474,665	0.8804%	

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation			
3		Automobile	Factors, Cost of Service Factors, Time	$21		
4		Air Service	Studies and /or Actual Costs Incurred	143		
5		Contract Services		116		
6		Employee Reimbursable Expense		111		
7		Materials		962		
8		Office Expenses		357		
9		Office Telephone		69,608		
10		Organizational Dues		17		
11		Payroll		9,142		
12		Permits & Filing Fees		287		
13		Seminars & Meeting Registrations		98		
14						
15						
16		Office Services	* General Office Complex and Office			
17		Automobile	Supplies Cost of Service Allocation	87		
18		Contract Services	Factors	1,544		
19		Employee Meetings		64		
20		Express Mail		10,054		
21		Freight		793		
22		Office Expenses		5,388		
23		Postage		8,048		
24		Cost of Service - General Office Buildings		408,700		$97,610
25						
26		Information Systems	* Various Corporate Overhead Allocation			
27		Automobile	Factors and /or Actual Costs Incurred	22		
28		Air Service		52		
29		Contract Services		164		
30		Employee Benefits				
31		Corporate Aircraft				
32		Employee Reimbursable Expense		124		
33		Meals & Entertainment		84		
34		Office Expenses		19,090		

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	Payroll		19,880		
2		Reference Material		45		
3		Seminars & Meeting Registrations		398		
4		Software Maintenance		3,635		
5						
6						
7		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
8		Automobile	Factors and /or Actual Costs Incurred	38		
9		Employee Benefits		1,730		
10		Employee Reimbursable Expense		3		
11		Office Telephone		5		
12		Payroll		1,271		
13						
14		Other Direct Charges	Actual Costs Incurred			
15		Utility Discounts		60,798		6,985
16		Corporate/Commercial Air Service		31,688		
17		Computer/Software Costs		155,013		
18		Rubber Glove Testing		1,732		
19		Electric Consumption		1,002,171		75,537
20		Gas Consumption		94,909		90,059
21		Telephone		33,070		
22		Miscellaneous		27,673		
23		SISP death proceeds		(11,216)		
24		Region Contract Services		1,462		
25						
26						
27						
28		**Total Montana-Dakota Utilities Co.**		$1,959,381	0.2664%	$270,191

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	OTHER TRANSACTIONS/REIMBURSEMENTS				
2		Overrefund of Brazil Corp Development		($382,101)		
3		Insurance		873		
4		Federal & State Tax Liability Payments		24,035,657		
5		KESOP carrying costs		303,946		
6		Tax Deferred Savings Plan		79,025		
7		Interest		(67,167)		
8		Miscellaneous Reimbursements		40,282		
9						
10		**Total Other Transactions/Reimbursements**		$24,010,515	3.2647%	
11						
12		**Grand Total Affiliate Transactions**		$32,444,561	4.4115%	$270,191
13						
14						
15						
16		**Total Knife River Corporation Operating Expenses for 2001**			$735,447,724	

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$14,278		
4		Advertising	Costs Incurred	17,329		
5		Air Service		58,304		
6		Automobile		6,223		
7		Bank Services		85,015		
8		Corporate Aircraft		30,505		
9		Consultant Fees		174,513		
10		Contract Services		219,988		
11		Directors Expenses		654,863		
12		Employee Benefits		33,541		
13		Employee Meeting		27,161		
14		Employee Reimbursable Expense		68,753		
15		Express Mail		613		
16		Freight		9		
17		Legal Retainers & Fees		250,169		
18		Meal Allowance		289		
19		Cash Donations		9,139		
20		Meal & Entertainment		40,310		
21		Moving Expense		290		
22		Industry Dues & Licenses		25,047		
23		Office Expenses		20,382		
24		Supplemental Insurance		(7,944)		
25		Permits & Filing Fees		4,669		
26		Postage		6,403		
27		Payroll		2,186,393		
28		Reference Materials		22,726		
29		Rental		2,879		
30		Seminars & Meeting Registrations		23,416		
31		Software Maintenance		9,894		
32		Training Material		19,702		
33		**Total MDU Resources Group, Inc.**		$4,004,859	0.7352%	

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation			
3		Expense	Factors, Cost of Service Factors, Time			
4		Automobile	Studies and /or Actual Costs Incurred	$2,900		
5		Air Service		536		
6		Annual Easements		2,560		
7		Contract Services		5,206		
8		Custodial Services		390		
9		Employee Reimbursable Expense		1,546		
10		Freight		54		
11		Materials		4,165		
12		Meals & Entertainment		773		
13		Office Expenses		738		
14		Office Telephone		34,846		
15		Payroll		58,402		
16		Permits & Filing Fees		516		
17		Photocopier		504		
18		Reference Material		19		
19		Seminars & Meeting Registrations		275		
20		Utilities		3,608		
21						
22		Office Services	* General Office Complex and Office			
23		Expense	Supplies cost of Service Allocation			
24		Automobile	Factors	109		
25		Contract Services		1,972		
26		Employee Meetings		82		
27		Express Mail		5,539		
28		Freight				
29		Office Expenses		24,641		
30		Postage		4,567		
31		Cost of Service - General Office Buildings		428,046		$102,231
32						
33						

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Purchasing Department	* Various Corporate Overhead Allocation			
2		Capital	Factors, Cost of Service Factors, Time			
3		Payroll	Studies and /or Actual Costs Incurred	29,240		
4						
5		Information Systems	* Various Corporate Overhead Allocation			
6		Expense	Factors and /or Actual Costs Incurred			
7		Automobile		36		
8		Air Service		42		
9		Contract Services		1,448		
10		Employee Reimbursable Expense		62		
11		Meals & Entertainment		40		
12		Office Expenses		124,954		
13		Payroll		8,528		
14		Reference Material		324		
15		Seminars & Meeting Registrations		1,548		
16		Software Maintenance		2,003		
17						
18		Region Operations	Actual Costs Incurred			
19		Expense				
20		Automobile		2,655		
21		Contract Services		41		
22		Freight		10		
23		Materials		30		
24		OfficeTelephone		110		
25		Payroll		10,099		
26		Utilities		187		

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Transportation Department	* Various Corporate Overhead Allocation			
2		Capital	Factors, Time Studies and /or Actual			
3		Payroll	Costs incurred	12,198		
4		Clearing Accounts				
5		Automobile		1,913		
6		Air Service				
7		Contract Services		30		
8		Corporate Aircraft		231		
9		Custodial Services		329		
10		Employee Reimbursable Expense		167		
11		Materials		328		
12		Meals & Entertainment		130		
13		Office Expenses		13		
14		Office Telephone		431		
15		Payroll		6,524		
16		Utilities		512		
17						
18		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
19		Expense	Factors, Time Studies and /or Actual			
20		Automobile	Costs incurred	176		
21		Employee Reimbursable Expense		7		
22		Employee Benefits		982		
23		Legal Fees		305		
24		Office Telephone		1		
25		Payroll		3,307		
26		Training Material		4		
27						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Capital				
2		Automobile		343		
3		Air Service		679		
4		Contract Services		81		
5		Employee Reimbursable Expense		490		
6		Meals & Entertainment		211		
7		Office Expenses		38		
8		Payroll		2,003		
9						
10		Other Direct Charges	Actual Costs Incurred			
11		Utility/Merchandise Discounts		132,211		77,412
12		Corporate Aircraft		80,204		
13		Contract Services		264,967		
14		Vehicle Maintenance		27,078		
15		Cathodic Protection		12,796		4,359
16		Purchased Power for Compressor Stations		75,453		65,110
17		Electric Compressor - Electricity Cost		90,397		13,652
18		Office Building Utilities		141,755		84,244
19		SISP Death Proceeds		(6,179)		
20		Miscellaneous		76,142		
21		Pool Car Usage		2,434		
22						
23		Total Montana-Dakota Utilities Co. 1/		$1,692,042	0.3106%	$347,008
24						
25		1/ Total Montana-Dakota Charges By Category				
26		Expense		$1,636,151	0.3004%	
27		Capital		45,283	0.0083%	
28		Clearing		10,608	0.0019%	
29		Total		$1,692,042	0.3106%	
30						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	OTHER TRANSACTIONS/REIMBURSEMENTS				
2		Insurance	Actual Costs Incurred	$63,130		
3		Federal & State Tax Liability Payments		34,205,082		
4		Tax Deferred Savings Plan		44,254		
5		KESOP carrying costs		403,944		
6		Interest		(37,006)		
7		Miscellaneous Reimbursements				
8		Overrefund of Brazil Corp Development		(210,527)		
9		**Total Other Transactions/Reimbursements**		$34,468,877	6.3279%	
10						
11		**Grand Total Affiliate Transactions**		$40,165,778	7.3737%	$347,008
12						
13						
14						
15		**Total WBI Holdings Operating Expenses for 2001**			$544,715,762	

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	UTILITY SERVICES, INC.	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$1,635		
4		Advertising	Costs Incurred	1,983		
5		Air Service		10,833		
6		Automobile		218		
7		Bank Services		9,737		
8		Corporate Aircraft		3,326		
9		Consultant Fees		17,980		
10		Contract Services		26,130		
11		Directors Expenses		85,629		
12		Employee Benefits		4,509		
13		Employee Meeting		3,111		
14		Employee Reimbursable Expense		9,536		
15		Express Mail		70		
16		Legal Retainers & Fees		31,265		
17		Moving Allowance		33		
18		Meal Allowance		32		
19		Cash Donations		1,006		
20		Meal & Entertainment		4,126		
21		Industry Dues & Licenses		2,097		
22		Office Expenses		2,199		
23		Supplemental Insurance		(910)		
24		Permits & Filing Fees		549		
25		Postage		727		
26		Payroll		290,256		
27		Reference Materials		2,511		
28		Rent		109		
29		Seminars & Meeting Registrations		2,942		
30		Software Maintenance		1,133		
31		Training Material		2,257		
32		**Total MDU Resources Group, Inc.**		$515,029	0.1517%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	UTILITY SERVICES, INC.	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation			
3		Air Service	Factors, Cost of Service Factors, Time	$2		
4		Contract Services	Studies and /or Actual Costs Incurred	2		
5		Office Expenses		30		
6		Office Telephone		2,301		
7		Payroll		193		
8		Employee Reimbursable Expense		6		
9		Permits & Filing Fees		18		
10		Seminars & Meeting Registrations		2		
11						
12						
13		Office Services	* General Office Complex and Office			
14		Automobile	Supplies Cost of Service Allocation	4		
15		Contract Services	Factors	93		
16		Employee Meetings		4		
17		Express Mail		637		
18		Office Expenses		347		
19		Postage		489		
20		Cost of Service - General Office Buildings		187,415		$44,761
21						
22		Information Systems	* Various Corporate Overhead Allocation			
23		Contract Services	Factors and /or Actual Costs Incurred	10		
24		Employee Reimbursable Expense		10		
25		Office Expenses		836		
26		Payroll		1,163		
27		Reference Material		2		
28		Seminars & Meeting Registrations		14		
29		Software Maintenance		230		

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	UTILITY SERVICES, INC.	Business Development	* Various Corporate Overhead Allocation			
2		Air Service	Factors, Time Studies and/or	1,622		
3		Meals and Entertainment	Actual Costs Incurred	340		
4		Employee Reimbursable Expense		2,046		
5		Office Expenses		6,721		
6						
7		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
8		Corporate Aircraft	Factors, Time Studies and/or			
9		Employee Benefits	Actual Costs Incurred	1,234		
10		Employee Reimbursable Expense				
11		Payroll		40		
12		Seminars & Meeting Registrations		3,125		
13		Training Material				
14						
15		Other Direct Charges	Actual Costs Incurred			
16		Legal Fees		121,078		
17		Contract Services		13,936		
18		Air Service		25,802		
19		Meals and Entertainment		1,621		
20		Employee Reimbursable Expense		41,986		
21		Consulting Service		38,457		
22		Permits and Filing Fees		70,844		
23						
24		**Total Montana-Dakota Utilities Co.**		$522,660	0.1539%	$44,761

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	UTILITY SERVICES, INC.	OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
2		Federal & State Tax Liability Payments		$10,576,824		
3		Audit fees		65,500		
4		Insurance		383,675		
5		Charitable contributions		47,912		
6		Miscellaneous		27,154		
7		KESOP carrying costs		12,763		
8						
9		**Total Other Transactions/Reimbursements**		$11,113,828	3.2731%	
10						
11		**Grand Total Affiliate Transactions**		$12,151,517	3.5787%	$44,761
12						
13						
14						
15		**Total Utility Services, Inc. Operating Expenses for 2001**			$ 339,551,151	

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU INTERNATIONAL	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Air Service	Factors, Time Studies and/or Actual	$66,854		
4		Consultant Fees	Costs Incurred	321,877		
5		Contract Services		7,848		
6		Employee Benefits		295		
7		Employee Reimbursable Expense		12,111		
8		Legal Retainers & Fees		896,541		
9		Meal & Entertainment		3,044		
10		Office Expenses		759		
11		Reference Materials		107		
12		Total MDU Resources Group, Inc.		$1,309,436		
13						
14		OTHER TRANSACTIONS/REIMBURSEMENTS				
15		Employee Reimbursable Expense		$1,693		
		Legal Retainers & Fees		3,766		
16		Miscellaneous		5,085		
17		**Total Other Transactions/Reimbursements**		$10,544		
18						
19		**Grand Total Affiliate Transactions**		$1,319,980		
20						
21						

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2001

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL HOLDINGS	MDU RESOURCES GROUP, INC.				
2	CAPITAL CORP.	Corporate Overhead	* Various Corporate Overhead Allocation			
3		Air Service	Factors, Time Studies and/or Actual	$3,043		
4		Automobile	Costs Incurred	12		
5		Contract Services		780		
6		Employee Reimbursable Expense		12,988		
7		Industry Dues & Licenses		400		
8		Insurance		66,011		
9		Materials		2,661		
10		Meal & Entertainment		122		
11		Payroll		248,753		
12		Reference Materials		27		
13		Training		16,100		
14		**Total MDU Resources Group, Inc.**		$350,897		
15						
16		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
17		Air Service		$30,660		
18		Contract Services		14,556		
19		Consulting Fees		77,572		
20		Corporate Aircraft		7,039		
21		Employee Reimbursable Expense		274		
22		Fuel		36,302		
23		Insurance		5,706		
24		Legal Retainers & Fees		21,995		
25		Miscellaneous		1,170		
26		Office Expenses		9,230		
27		Permits and Filing Fees		4,398		
28		Rent		2,100		
29		Electric and gas consumption		28,863		
30		**Total Other Transactions/Reimbursements**		$239,865		
31						
32		**Grand Total Affiliate Transactions**		$590,762		
33						
33						

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

MONTANA UTILITY INCOME STATEMENT

Year: 2001

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	$64,406,017	$64,354,421	-0.08%
2				
3	Operating Expenses			
4	401 Operation Expenses	$55,962,430	$57,848,757	3.37%
5	402 Maintenance Expense	699,567	767,611	9.73%
6	403 Depreciation Expense	2,015,775	2,080,690	3.22%
7	404-405 Amort. & Depl. of Gas Plant	128,628	151,002	17.39%
8	406 Amort. of Gas Plant Acquisition Adjustments			
9	407.1 Amort. of Property Losses, Unrecovered Plant			
10	& Regulatory Study Costs			
11	407.2 Amort. of Conversion Expense			
12	408.1 Taxes Other Than Income Taxes	2,010,273	2,209,566	9.91%
13	409.1 Income Taxes - Federal	1,803,199	1,928,616	6.96%
14	- Other	370,657	461,924	24.62%
15	410.1 Provision for Deferred Income Taxes	(1,092,017)	(1,755,496)	-60.76%
16	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	5,087	(227,526)	-4572.70%
17	411.4 Investment Tax Credit Adjustments			
18	411.6 (Less) Gains from Disposition of Utility Plant			
19	411.7 Losses from Disposition of Utility Plant			
20	**TOTAL Utility Operating Expenses**	$61,903,599	$63,465,144	2.52%
21	**NET UTILITY OPERATING INCOME**	$2,502,418	$889,277	-64.46%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Gas			
2	480 Residential	$36,482,551	$42,258,645	15.83%
3	481 Commercial & Industrial - Small	21,541,829	25,206,559	17.01%
4	Commercial & Industrial - Large		298	100.00%
5	482 Other Sales to Public Authorities			
6	484 Interdepartmental Sales			
7	485 Intracompany Transfers			
8	Net Unbilled Revenue	5,129,195	(4,410,333)	-185.98%
9	**TOTAL Sales to Ultimate Consumers**	63,153,575	63,055,169	-0.16%
10	483 Sales for Resale			
11	**TOTAL Sales of Gas**	$63,153,575	$63,055,169	-0.16%
12	Other Operating Revenues			
13	487 Forfeited Discounts & Late Payment Revenues			
14	488 Miscellaneous Service Revenues	$13,578	$45,349	233.99%
15	489 Revenues from Transp. of Gas for Others 1/	1,050,794	1,105,062	5.16%
16	490 Sales of Products Extracted from Natural Gas			
17	491 Revenues from Nat. Gas Processed by Others			
18	492 Incidental Gasoline & Oil Sales			
19	493 Rent From Gas Property	122,158	133,175	9.02%
20	494 Interdepartmental Rents			
21	495 Other Gas Revenues	65,912	15,666	-76.23%
22	**TOTAL Other Operating Revenues**	1,252,442	1,299,252	3.74%
23	**Total Gas Operating Revenues**	$64,406,017	$64,354,421	-0.08%
24				
25	496 (Less) Provision for Rate Refunds			
26				
27	**TOTAL Oper. Revs. Net of Pro. for Refunds**	$64,406,017	$64,354,421	-0.08%

1/ Includes unbilled revenue.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2001

	Account Number & Title	Last Year	This Year	% Change
1	**Production Expenses**			
2	Production & Gathering - Operation			
3	750 Operation Supervision & Engineering			
4	751 Production Maps & Records			
5	752 Gas Wells Expenses			
6	753 Field Lines Expenses			
7	754 Field Compressor Station Expenses		NOT	
8	755 Field Compressor Station Fuel & Power		APPLICABLE	
9	756 Field Measuring & Regulating Station Expense			
10	757 Purification Expenses			
11	758 Gas Well Royalties			
12	759 Other Expenses			
13	760 Rents			
14	**Total Operation - Natural Gas Production**			
15	Production & Gathering - Maintenance			
16	761 Maintenance Supervision & Engineering			
17	762 Maintenance of Structures & Improvements			
18	763 Maintenance of Producing Gas Wells			
19	764 Maintenance of Field Lines			
20	765 Maintenance of Field Compressor Sta. Equip.		NOT	
21	766 Maintenance of Field Meas. & Reg. Sta. Equip.		APPLICABLE	
22	767 Maintenance of Purification Equipment			
23	768 Maintenance of Drilling & Cleaning Equip.			
24	769 Maintenance of Other Equipment			
25	**Total Maintenance- Natural Gas Prod.**			
26	**TOTAL Natural Gas Production & Gathering**			
27	Products Extraction - Operation			
28	770 Operation Supervision & Engineering			
29	771 Operation Labor			
30	772 Gas Shrinkage			
31	773 Fuel			
32	774 Power			
33	775 Materials			
34	776 Operation Supplies & Expenses		NOT	
35	777 Gas Processed by Others		APPLICABLE	
36	778 Royalties on Products Extracted			
37	779 Marketing Expenses			
38	780 Products Purchased for Resale			
39	781 Variation in Products Inventory			
40	782 (Less) Extracted Products Used by Utility - Cr.			
41	783 Rents			
42	**Total Operation - Products Extraction**			
43	Products Extraction - Maintenance			
44	784 Maintenance Supervision & Engineering			
45	785 Maintenance of Structures & Improvements			
46	786 Maintenance of Extraction & Refining Equip.			
47	787 Maintenance of Pipe Lines		NOT	
48	788 Maintenance of Extracted Prod. Storage Equip.		APPLICABLE	
49	789 Maintenance of Compressor Equipment			
50	790 Maintenance of Gas Meas. & Reg. Equip.			
51	791 Maintenance of Other Equipment			
52	**Total Maintenance - Products Extraction**			
53	**TOTAL Products Extraction**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2001

	Account Number & Title	Last Year	This Year	% Change
1	**Production Expenses - continued**			
2				
3	Exploration & Development - Operation			
4	795 Delay Rentals			
5	796 Nonproductive Well Drilling		NOT	
6	797 Abandoned Leases		APPLICABLE	
7	798 Other Exploration			
8	**TOTAL Exploration & Development**			
9				
10	Other Gas Supply Expenses - Operation			
11	800 Natural Gas Wellhead Purchases			
12	800.1 Nat. Gas Wellhead Purch., Intracomp. Trans.			
13	801 Natural Gas Field Line Purchases			
14	802 Natural Gas Gasoline Plant Outlet Purchases			
15	803 Natural Gas Transmission Line Purchases			
16	804 Natural Gas City Gate Purchases	$42,265,379	$49,165,955	16.33%
17	805 Other Gas Purchases			
18	805.1 Purchased Gas Cost Adjustments	2,849,770	5,154,891	80.89%
19	805.2 Incremental Gas Cost Adjustments			
20	806 Exchange Gas			
21	807.1 Well Expenses - Purchased Gas			
22	807.2 Operation of Purch. Gas Measuring Stations			
23	807.3 Maintenance of Purch. Gas Measuring Stations			
24	807.4 Purchased Gas Calculations Expenses			
25	807.5 Other Purchased Gas Expenses			
26	808.1 Gas Withdrawn from Storage -Dr.	6,579,026	8,926,986	35.69%
27	808.2 (Less) Gas Delivered to Storage -Cr.	(3,941,334)	(14,149,207)	-259.00%
28	809.2 (Less) Deliveries of Nat. Gas for Processing-Cr.			
29	810 (Less) Gas Used for Compressor Sta. Fuel-Cr.			
30	811 (Less) Gas Used for Products Extraction-Cr.			
31	812 (Less) Gas Used for Other Utility Operations-Cr.	292		-100.00%
32	813 Other Gas Supply Expenses	130,233	138,697	6.50%
33	**TOTAL Other Gas Supply Expenses**	$47,883,366	$49,237,322	2.83%
34				
35	**TOTAL PRODUCTION EXPENSES**	$47,883,366	$49,237,322	2.83%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2001

	Account Number & Title		Last Year	This Year	% Change
1	**Storage, Terminaling & Processing Expenses**				
2					
3	Underground Storage Expenses - Operation				
4	814	Operation Supervision & Engineering			
5	815	Maps & Records			
6	816	Wells Expenses			
7	817	Lines Expenses			
8	818	Compressor Station Expenses			
9	819	Compressor Station Fuel & Power		NOT	
10	820	Measuring & Reg. Station Expenses		APPLICABLE	
11	821	Purification Expenses			
12	822	Exploration & Development			
13	823	Gas Losses			
14	824	Other Expenses			
15	825	Storage Well Royalties			
16	826	Rents			
17		**Total Operation - Underground Strg. Exp.**			
18					
19	Underground Storage Expenses - Maintenance				
20	830	Maintenance Supervision & Engineering			
21	831	Maintenance of Structures & Improvements			
22	832	Maintenance of Reservoirs & Wells			
23	833	Maintenance of Lines			
24	834	Maintenance of Compressor Station Equip.		NOT	
25	835	Maintenance of Meas. & Reg. Sta. Equip.		APPLICABLE	
26	836	Maintenance of Purification Equipment			
27	837	Maintenance of Other Equipment			
28		**Total Maintenance - Underground Storage**			
29		**TOTAL Underground Storage Expenses**			
30					
31	Other Storage Expenses - Operation				
32	840	Operation Supervision & Engineering			
33	841	Operation Labor and Expenses			
34	842	Rents		NOT	
35	842.1	Fuel		APPLICABLE	
36	842.2	Power			
37	842.3	Gas Losses			
38		**Total Operation - Other Storage Expenses**			
39					
40	Other Storage Expenses - Maintenance				
41	843.1	Maintenance Supervision & Engineering			
42	843.2	Maintenance of Structures & Improvements			
43	843.3	Maintenance of Gas Holders			
44	843.4	Maintenance of Purification Equipment		NOT	
45	843.6	Maintenance of Vaporizing Equipment		APPLICABLE	
46	843.7	Maintenance of Compressor Equipment			
47	843.8	Maintenance of Measuring & Reg. Equipment			
48	843.9	Maintenance of Other Equipment			
49		**Total Maintenance - Other Storage Exp.**			
50		**TOTAL - Other Storage Expenses**			
51					
52	**TOTAL - STORAGE, TERMINALING & PROC.**				

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2001

	Account Number & Title		Last Year	This Year	% Change
1		**Transmission Expenses**			
2	Operation				
3	850	Operation Supervision & Engineering			
4	851	System Control & Load Dispatching			
5	852	Communications System Expenses			
6	853	Compressor Station Labor & Expenses			
7	854	Gas for Compressor Station Fuel		NOT	
8	855	Other Fuel & Power for Compressor Stations		APPLICABLE	
9	856	Mains Expenses			
10	857	Measuring & Regulating Station Expenses			
11	858	Transmission & Compression of Gas by Others			
12	859	Other Expenses			
13	860	Rents			
14		**Total Operation - Transmission**			
15	Maintenance				
16	861	Maintenance Supervision & Engineering			
17	862	Maintenance of Structures & Improvements			
18	863	Maintenance of Mains			
19	864	Maintenance of Compressor Station Equip.		NOT	
20	865	Maintenance of Measuring & Reg. Sta. Equip.		APPLICABLE	
21	866	Maintenance of Communication Equipment			
22	867	Maintenance of Other Equipment			
23		**Total Maintenance - Transmission**			
24		**TOTAL Transmission Expenses**			
25		**Distribution Expenses**			
26	Operation				
27	870	Operation Supervision & Engineering	$353,142	$350,898	-0.64%
28	871	Distribution Load Dispatching	49,313	50,922	3.26%
29	872	Compressor Station Labor and Expenses			
30	873	Compressor Station Fuel and Power			
31	874	Mains and Services Expenses	742,112	652,780	-12.04%
32	875	Measuring & Reg. Station Exp.-General	28,596	26,987	-5.63%
33	876	Measuring & Reg. Station Exp.-Industrial	12,948	15,541	20.03%
34	877	Meas. & Reg. Station Exp.-City Gate Ck. Sta.			
35	878	Meter & House Regulator Expenses	445,329	411,161	-7.67%
36	879	Customer Installations Expenses	748,558	775,730	3.63%
37	880	Other Expenses	716,857	844,025	17.74%
38	881	Rents	18,659	21,722	16.42%
39		**Total Operation - Distribution**	$3,115,514	$3,149,766	1.10%
40	Maintenance				
41	885	Maintenance Supervision & Engineering	$149,921	$137,990	-7.96%
42	886	Maintenance of Structures & Improvements	245	1,492	508.98%
43	887	Maintenance of Mains	74,335	84,303	13.41%
44	888	Maint. of Compressor Station Equipment			
45	889	Maint. of Meas. & Reg. Station Exp.-General	21,076	14,443	-31.47%
46	890	Maint. of Meas. & Reg. Sta. Exp.-Industrial	6,830	2,684	-60.70%
47	891	Maint. of Meas. & Reg. Sta. Equip.-City Gate			
48	892	Maintenance of Services	77,594	115,995	49.49%
49	893	Maintenance of Meters & House Regulators	103,582	57,633	-44.36%
50	894	Maintenance of Other Equipment	93,168	172,442	85.09%
51		**Total Maintenance - Distribution**	$526,751	$586,982	11.43%
52		**TOTAL Distribution Expenses**	$3,642,265	$3,736,748	2.59%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2001

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Customer Accounts Expenses**			
3	Operation			
4	901 Supervision	$129,792	$137,449	5.90%
5	902 Meter Reading Expenses	413,917	484,793	17.12%
6	903 Customer Records & Collection Expenses	1,147,767	1,194,825	4.10%
7	904 Uncollectible Accounts Expenses	280,535	409,285	45.89%
8	905 Miscellaneous Customer Accounts Expenses	144,627	120,766	-16.50%
9				
10	**TOTAL Customer Accounts Expenses**	$2,116,638	$2,347,118	10.89%
11				
12	**Customer Service & Informational Expenses**			
13	Operation			
14	907 Supervision	$3,986	$4,392	10.19%
15	908 Customer Assistance Expenses	22,050	26,763	21.37%
16	909 Informational & Instructional Advertising Exp.	22,291	30,000	34.58%
17	910 Miscellaneous Customer Service & Info. Exp.	365	437	19.73%
18				
19	**TOTAL Customer Service & Info. Expenses**	$48,692	$61,592	26.49%
20				
21	**Sales Expenses**			
22	Operation			
23	911 Supervision	$106,295	$103,745	-2.40%
24	912 Demonstrating & Selling Expenses	205,354	217,392	5.86%
25	913 Advertising Expenses	27,180	28,772	5.86%
26	916 Miscellaneous Sales Expenses	20,884	19,465	-6.79%
27				
28	**TOTAL Sales Expenses**	$359,713	$369,374	2.69%
29				
30	**Administrative & General Expenses**			
31	Operation			
32	920 Administrative & General Salaries	$768,532	$900,301	17.15%
33	921 Office Supplies & Expenses	374,713	512,849	36.86%
34	922 (Less) Administrative Expenses Transferred - Cr.			
35	923 Outside Services Employed	131,448	147,748	12.40%
36	924 Property Insurance	26,004	37,968	46.01%
37	925 Injuries & Damages	239,396	180,674	-24.53%
38	926 Employee Pensions & Benefits	717,506	725,920	1.17%
39	927 Franchise Requirements			
40	928 Regulatory Commission Expenses	1,190	1,193	0.25%
41	929 (Less) Duplicate Charges - Cr.			
42	930.1 General Advertising Expenses	20,756	27,600	32.97%
43	930.2 Miscellaneous General Expenses	150,554	127,614	-15.24%
44	931 Rents	8,408	21,718	158.30%
45				
46	**TOTAL Operation - Admin. & General**	$2,438,507	$2,683,585	10.05%
47	Maintenance			
48	935 Maintenance of General Plant	$172,816	$180,629	4.52%
49				
50	**TOTAL Administrative & General Expenses**	$2,611,323	$2,864,214	9.68%
51	**TOTAL OPERATION & MAINTENANCE EXP.**	$56,661,997	$58,616,368	3.45%

MONTANA TAXES OTHER THAN INCOME

Year: 2001

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$423,963	$418,998	-1.17%
2	Secretary of State	146	152	4.11%
3	Highway Use Tax		131	100.00%
4	Montana Consumer Counsel	49,090	54,724	11.48%
5	Montana PSC	154,423	186,032	20.47%
6	Franchise Taxes	15,494	15,061	-2.79%
7	Property Taxes	1,361,457	1,528,768	12.29%
8	Tribal Taxes	5,700	5,700	0.00%
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50	**TOTAL MT Taxes other than Income**	$2,010,273	$2,209,566	9.91%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2001

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Arthur Andersen LLP	Auditing and Consulting Services	329,738	$9,955	3.02%
2					
3	Bullinger Tree Service	Tree Trimming Service	183,266	0	0.00%
4					
5	Chief Construction	Construction Services	455,595	0	0.00%
6					
7	Christensen & Associates	Consultant - Investor Relations	88,407	2,935	3.32%
8					
9	Cynthia J. Skibinski	Consultant - CIS System	194,715	19,164	9.84%
10					
11	Dakota Line Contractors	Construction Services	108,313	35	0.03%
12					
13	Diversified Graphics Inc.	Annual Report	116,455	3,866	3.32%
14					
15	Duffield Construction, Inc.	Construction Services	132,699	0	0.00%
16					
17	Empire Roofing, Inc.	Construction Services	96,900	43,579	44.97%
18					
19	Enviro Safe Air	Contract Services - Asbestos Removal	205,624	0	0.00%
20					
21	Faberworks	Consultant	138,517	13,839	9.99%
22					
23	GE-Harris	Construction Services	313,143	0	0.00%
24					
25	Gustafson Builders	Construction Services	3,154,940	0	0.00%
26					
27	Hamilton Spray	Contract Services - Pole Treatment	215,390	0	0.00%
28					
29	Hamlin Electric Company	Construction Services	271,009	0	0.00%
30					
31	Hedahl's of Bismarck	Contract Services - Auto and Work Equip.	164,550	618	0.38%
32					
33	Hosler Maps, Inc.	Contract Services - Map Conversion	142,457	14,233	9.99%
34					
35	Hughes, Kellner, Sullivan	Legal Services	107,660	52,511	48.77%
36					
37	IBM	Contract Services - Computer Maintenance	96,786	13,945	14.41%
38					
39	Image Printing, Inc.	Printing Services	70,034	2,273	3.25%
40					
41	Industrial Contractors, Inc.	Construction Services	283,782	0	0.00%
42					
43	Interiors By France	Contract Services - Interior Decorators	125,225	6,907	5.52%
44					
45	Intermountain Tree Expert Co.	Tree Trimming Service	95,770	0	0.00%
46					
47	James W. Sewall Company	Consulting Services	143,780	16,414	11.42%
48					
49	J. B. Construction, Inc.	Construction Services	215,066	0	0.00%
50					
51	J.D. Edwards	Contract Services - Software Maintenance	164,483	15,823	9.62%
52					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2001

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Knife River Corporation	Software Maintenance Fees	88,107	8,642	9.81%
2					
3	Leboeuf, Lamb, Greene & MacRae	Legal Services	158,443	5,260	3.32%
4					
5	Lignite Energy Council	Organization Dues and Assessments	77,197	0	0.00%
6					
7	Lowe Inc.	Consulting Services	200,000	0	0.00%
8					
9	Mappcor	Organization Dues and Assessments	200,568	0	0.00%
10					
11	McDermott, Will & Emery	Legal Services	85,990	3,086	3.59%
12					
13	Miner & Miner	Consultant	206,451	23,568	11.42%
14					
15	New York Life	K-Plan Administrator	83,811	0	0.00%
16					
17	New York Stock Exchange	Financial Services	72,747	2,316	3.18%
18					
19	Oakland & Fisher Construction	Construction Services	95,675	0	0.00%
20					
21	One Call Locators, Inc.	Line Location Service	795,920	197,429	24.81%
22					
23	Osmose Wood	Contract Services - Pole Treatment	304,510	0	0.00%
24					
25	Philip Service Corporation	Contract Services - Power Plant	134,198	0	0.00%
26					
27	Progressive Maintenance	Custodial Services	102,418	7,974	7.79%
28					
29	Pole Maintenance Company	Contract Services - Pole Treatment	90,540	0	0.00%
30					
31	Robert Panero Associates	Consultant	169,042	5,612	3.32%
32					
33	Rocky Mountain Contractors, Inc.	Construction Services	220,208	220,208	0.00%
34					
35	Rocky Mountain Line	Construction Services	434,471	17,382	4.00%
36					
37	Rodman L. Drake	Consultant	78,973	2,622	3.32%
38					
39	Skeels Electric Company	Contract Services - Electrical	72,469	7,191	9.92%
40					
41	Southern Cross Corporation	Contract Services - Leak Detection	133,860	41,688	31.14%
42					
43	State-Line Contractors, Inc.	Construction Services	85,952	82,822	96.36%
44					
45	Thelen, Reid, & Priest LLP	Legal Services	1,859,356	26,557	1.43%
46					
47	Towers Perrin	Consultant - Compensation and Benefits	370,423	13,515	3.65%
48					
49	TSP Three Inc.	Construction Services	99,130	0	0.00%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2001

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Truesecure Corporation	Information System Security	159,315	5,289	3.32%
2					
3	Underground Locators, LLC	Line Location Service	101,081	0	0.00%
4					
5	US Bank	Bank Services	111,361	17,832	16.01%
6					
7	Utility Partners, LC	Consultant - Mobile Service Computer	151,807	14,435	9.51%
8					
9	Utility Shareholders	Organization Dues and Assessments	125,000	0	0.00%
10					
11	Veirano & Advogados Associates	Legal Services	128,897	0	0.00%
12					
13	Wells Fargo	Stock Transfer Agent and ESOP Admin	341,565	11,340	3.32%
14					
15	**TOTAL Payments for Services**		$14,953,789	$930,865	6.22%

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2001

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	$6,461	$1,275	19.73%
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43	**TOTAL Contributions**	$6,461	$1,275	19.73%

Pension Costs

Year: 2001

1	Plan Name MDU Resources Group, Inc. Master Pension Plan Trust			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: 1A		
4	Annual Contribution by Employer: 0	Is the Plan Over Funded? Yes		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**	(000's)	(000's)	
7	Benefit obligation at beginning of year	$141,394	$129,390	9.28%
8	Service cost	3,122	2,857	9.28%
9	Interest Cost	10,568	10,034	5.32%
10	Plan participants' contributions	-	-	0.00%
11	Amendments	(1,221)	5,010	-124.37%
12	Actuarial (Gain) Loss	6,546	5,713	14.58%
13	Acquisition	-	-	0.00%
14	Benefits paid	(9,164)	(11,610)	21.07%
15	Benefit obligation at end of year	$151,245	$141,394	6.97%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$194,845	$205,580	-5.22%
18	Actual return on plan assets	(10,623)	875	-1314.06%
19	Acquisition	-	-	0.00%
20	Employer contribution	-	-	0.00%
21	Plan participants' contributions	-	-	0.00%
22	Benefits paid	(9,164)	(11,610)	21.07%
23	Fair value of plan assets at end of year	$175,058	$194,845	-10.16%
24	**Funded Status**	$23,813	$53,451	-55.45%
25	Unrecognized net actuarial loss	(26,032)	(61,330)	57.55%
26	Unrecognized prior service cost	8,973	11,167	-19.65%
27	Unrecognized net transition obligation	(1,867)	(2,719)	31.34%
28	Accrued benefit cost	$4,887	$569	758.88%
29				
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	7.25	7.50	-3.33%
32	Expected return on plan assets	8.50	8.50	0.00%
33	Rate of compensation increase	5.00	5.00	0.00%
34				
35	**Components of Net Periodic Benefit Costs**			
36	Service cost	$3,122	$2,857	9.28%
37	Interest cost	10,568	10,034	5.32%
38	Expected return on plan assets	(15,837)	(14,734)	-7.49%
39	Amortization of prior service cost	972	709	37.09%
40	Recognized net actuarial gain	(2,292)	(2,244)	-2.14%
41	Transition amount amortization	(852)	(852)	0.00%
42	Net periodic benefit cost	($4,319)	($4,230)	-2.10%
43				
44	**Montana Intrastate Costs:**			
45	Pension Costs	($4,319)	($4,230)	-2.10%
46	Pension Costs Capitalized	(428)	(424)	-0.94%
47	Accumulated Pension Asset (Liability) at Year End	4,887	569	758.88%
48	**Number of Company Employees:**			
49	Covered by the Plan	1,941	1,988	-2.36%
50	Not Covered by the Plan	25	25	0.00%
51	Active	1,036	1,035	0.10%
52	Retired	851	844	0.83%
53	Deferred Vested Terminated	54	109	-50.46%

Other Post Employment Benefits (OPEBS)

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number:			
4	Order numbers:			
5	Amount recovered through rates -			
6	**Weighted-average Assumptions as of Year End**			
7	Discount rate	7.25	7.50	-3.33%
8	Expected return on plan assets	7.50	7.50	0.00%
9	Medical Cost Inflation Rate	6.00	6.00	0.00%
10	Actuarial Cost Method	Projected Unit Cost	Projected Unit Cost	
11	Rate of compensation increase	5.00	5.00	0.00%
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**VEBA**			
14	**Describe any Changes to the Benefit Plan:**			
15				
16				
	TOTAL COMPANY			
17	**Change in Benefit Obligation**	(000's)	(000's)	
18	Benefit obligation at beginning of year	$47,762	$45,753	4.39%
19	Service cost	857	766	11.88%
20	Interest Cost	3,357	3,440	-2.41%
21	Plan participants' contributions	713	560	27.32%
22	Amendments	-	-	0.00%
23	Actuarial (Gain) Loss	(1,063)	599	-277.46%
24	Acquisition	-	-	0.00%
25	Benefits paid	(3,083)	(3,356)	8.13%
26	Benefit obligation at end of year	$48,543	$47,762	1.64%
27	**Change in Plan Assets**			
28	Fair value of plan assets at beginning of year	$35,672	$36,271	-1.65%
29	Actual return on plan assets	(1,693)	(806)	-110.05%
30	Acquisition	-	-	0.00%
31	Employer contribution	2,782	3,003	-7.36%
32	Plan participants' contributions	713	560	27.32%
33	Benefits paid	(3,083)	(3,356)	8.13%
34	Fair value of plan assets at end of year	$34,391	$35,672	-3.59%
35	**Funded Status**	($14,152)	($12,090)	-17.06%
36	Unrecognized net actuarial loss	(7,909)	(11,809)	33.03%
37	Unrecognized prior service cost	-	-	0.00%
38	Unrecognized transition obligation	20,947	22,785	-8.07%
39	Accrued benefit cost	($1,114)	($1,114)	0.00%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	$857	$766	11.88%
42	Interest cost	3,357	3,440	-2.41%
43	Expected return on plan assets	(2,738)	(2,533)	-8.09%
44	Amortization of prior service cost	-	-	0.00%
45	Recognized net acturial gain	(532)	(508)	-4.72%
46	Transition amount amortization	1,838	1,838	0.00%
47	Net periodic benefit cost	$2,782	$3,003	-7.36%
48	**Accumulated Post Retirement Benefit Obligation**			
49	Amount Funded through VEBA	$3,495	$3,563	-1.91%
50	Amount Funded through 401(h)			
51	Amount Funded through Other ____________			
52	TOTAL	$3,495	$3,563	-1.91%
53	Amount that was tax deductible - VEBA	$2,782 1/	$3,706	-24.93%
54	Amount that was tax deductible - 401(h)			
55	Amount that was tax deductible - Other ____________			
56	TOTAL	$2,782	$3,706	-24.93%

1/ Estimated.

Other Post Employment Benefits (OPEBS) Continued

Year: 2001

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	1,776	1,772	0.23%
3	Not Covered by the Plan	25	25	0.00%
4	Active	984	986	-0.20%
5	Retired	598	600	-0.33%
6	Spouses/Dependants covered by the Plan	194	186	4.30%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost	NOT APPLICABLE		
11	Interest Cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss			
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost			
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			
39	Amount Funded through 401(h)			
40	Amount Funded through other ____________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension Costs			
48	Pension Costs Capitalized			
49	Accumulated Pension Asset (Liability) at Year End			
50	**Number of Montana Employees:**			
51	Covered by the Plan			
52	Not Covered by the Plan			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							

PROPRIETARY SCHEDULE

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 17

Year: 2001

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other 1/	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Martin A. White - Chairman of the Board, President & C.E.O.	$450,000	$374,500	$779,900	$1,604,400	$1,323,851	21%
2	Douglas C. Kane - Executive Vice President Chief Administrative & Corporate Development Officer	249,127	145,446	216,200	610,773	649,542	-6%
3	Ronald D. Tipton - C.E.O. of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co.	279,038	35,437	225,800	540,275	674,981	-20%
4	Warren L. Robinson - Executive Vice President, Treasurer & Chief Financial Officer	237,077	146,290	216,200	599,567	505,253	19%
5	Lester H. Loble, II - Vice President, General Counsel & Secretary	190,846	105,219	191,951	488,016	401,324	22%

1/ See page 20a for details.

EXECUTIVE COMPENSATION

TABLE 1: SUMMARY COMPENSATION TABLE

	Annual compensation				Long-term compensation			
					Awards		Payouts	
(a) Name and principal position	(b) Year	(c) Salary ($)	(d) Bonus(1) ($)	(e) Other annual compensation(2) ($)	(f) Restricted stock awards ($)	(g) Securities underlying Options/ SARs (#)	(h) LTIP payouts ($)	(i) All other compensation(7) ($)
Martin A. White	2001	450,000	374,500		594,800(3)	180,000(5)	—	5,100
—Chairman of the Board,	2000	394,269	333,239		198,125(4)	—	393,118(6)	5,100
President & C.E.O.	1999	323,077	203,960		229,063(4)	—	—	4,872
Douglas C. Kane	2001	249,127	145,446		148,700(3)	62,400(5)	—	5,100
—Executive Vice President,	2000	226,654	140,035		99,063(4)	—	178,690(6)	5,100
Chief Administrative &	1999	210,220	79,146		114,532(4)	—	—	5,100
Corporate Development Officer								
Ronald D. Tipton	2001	279,038	35,437		148,700(3)	72,000(5)	—	5,100
—C.E.O. of Montana-Dakota	2000	254,277	135,024		99,063(4)	—	181,517(6)	5,100
Utilities Co. and Great	1999	235,508	70,327		114,532(4)	—	—	4,863
Plains Natural Gas Co.								
Warren L. Robinson	2001	237,077	146,290		148,700(3)	62,400(5)	—	5,100
—Executive Vice President,	2000	188,462	110,912		79,250(4)	—	121,529(6)	5,100
Treasurer & Chief Financial	1999	172,396	86,591		91,625(4)	—	—	4,872
Officer								
Lester H. Loble, II	2001	190,846	105,219	13,291	118,960(3)	54,600(5)	—	5,100
—Vice President, General	2000	161,654	81,486	4,551	59,438(4)	—	89,345(6)	4,850
Counsel	1999	150,750	55,355	5,741	68,719(4)	—	—	4,523
& Secretary								

(1) Granted pursuant to the Executive Incentive Compensation Plan.

(2) Above-market interest on deferred compensation.

(3) Valued at fair market value on the date of grant. The restricted stock will vest nine years from the date of grant, assuming continued employment. Vesting of some or all shares may be accelerated if total shareholder return equals or exceeds the 50th percentile of the proxy peer group over a three year performance cycle. Nonpreferential dividends are paid on the restricted stock.

At December 31, 2001, the Named Officers held the following amounts of restricted stock: Mr. White—40,000 shares ($1,126,000); Mr. Kane—15,000 shares ($422,250); Mr. Tipton—15,000 shares ($422,250); Mr. Robinson—13,000 shares ($365,950); and Mr. Loble—10,000 shares ($281,500).

(4) Valued at fair market value on the date of grant. Nonpreferential dividends are paid on the restricted stock.

(5) Options granted pursuant to the 1992 KESOP or the 1997 Executive Long-Term Incentive Plan for the 2001-2003 performance cycle.

(6) Dividend equivalents paid with respect to options granted pursuant to the 1992 KESOP for the 1998-2000 performance cycle.

(7) Totals shown are the Company contributions to the Company 401(k) Retirement Plan.

TABLE 2: OPTION/SAR GRANTS IN LAST FISCAL YEAR

(a)	Individual Grants(1)				Grant date value
	(b)	(c)	(d)	(e)	(f)
Named Officer	Number of securities underlying options granted (#)	Percent of total options granted to employees in fiscal year(%)	Exercise or base price ($/share)	Expiration date	Grant date present value(2) ($)
Martin A. White	180,000	6.7	29.74	2/15/11	1,303,200
Douglas C. Kane	62,400	2.3	29.74	2/15/11	451,776
Ronald D. Tipton	72,000	2.7	29.74	2/15/11	521,280
Warren L. Robinson	62,400	2.3	29.74	2/15/11	451,776
Lester H. Loble, II	54,600	2.0	29.74	2/15/11	395,304

(1) All options were granted pursuant to the 1992 Key Employee Stock Option Plan or the 1997 Executive Long-Term Incentive Plan. The options become exercisable automatically in nine years on February 15, 2010. Vesting is accelerated upon change in control or upon attainment of certain performance goals, as follows: during the three year performance cycle (2001 - 2003) performance goals established for the Company by the Compensation Committee are based on return on equity (25%), earnings per share (25%) and total relative shareholder return (50%). Performance goals for Montana-Dakota Utilities Co. and the utility services companies, which are applicable to Mr. Tipton, are based on return on invested capital (60%) and earnings (40%). From 50% to 100% of the options granted may become exercisable at the end of the three year performance cycle if from 90% to 100% of the goals are met and, in the case of Mr. Tipton, if 94% to 100% of the goals are met.

Dividend Equivalents granted with the options are described in Table 4.

(2) Present values were calculated using the Black-Scholes option pricing model which has been adjusted to take dividends into account. Use of this model should not be viewed in any way as a forecast of the future performance of the Company's stock. The estimated present value of each stock option granted is $7.24 based on the following inputs:

Stock Price (fair market value) at Grant (2/14/01)	$ 29.74
Exercise Price	$ 29.74
Expected Option Term	7 Years
Stock Price Volatility	0.2594
Dividend Yield	3.53%

The model assumes: (a) a risk-free interest rate of 5.18 percent on a U.S. Treasury Note with a maturity date of approximately 7 years; (b) Stock Price Volatility is calculated using a three year historical average of stock prices from grant date; (c) Dividend Yield is calculated using the historical dividend rate for three years from the date of grant. The option value was not discounted to reflect any accelerated vesting of the options. Notwithstanding the fact that these options are non-transferable, no discount for lack of marketability was taken.

TABLE 3: AGGREGATED OPTION/SAR EXERCISES IN LAST FISCAL YEAR AND FISCAL YEAR-END OPTION/SAR VALUES

(a) Name	(b) Shares acquired on exercise (#)	(c) Value realized ($)	(d) Number of securities underlying unexercised options at fiscal year-end(1) (#)		(e) Value of unexercised, in-the-money options at fiscal year-end ($)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Martin A. White	62,000	1,141,570	60,760	180,000	413,168	
Douglas C. Kane	—	—	55,800	62,400	379,440	
Ronald D. Tipton	—	—	49,125	72,000	334,050	
Warren L. Robinson	—	—	37,950	62,400	258,060	
Lester H. Loble, II	8,750	231,934	34,000	54,600	284,829	

(1) Vesting is accelerated upon a change in control.

TABLE 4: LONG-TERM INCENTIVE PLAN—AWARDS IN LAST FISCAL YEAR

(a) Named Officer	(b) Number of shares, units or other rights (#)(1)	(c) Performance or other period until maturation or payout	Estimated future payouts under non-stock price-based plans. (d) Threshold ($)	(e) Target ($)	(f) Maximum ($)
Martin A. White	180,000	2001-2003	248,400	496,800	993,600
Douglas C. Kane	62,400	2001-2003	86,112	172,224	344,448
Ronald D. Tipton	72,000	2001-2003	99,360	198,720	397,440
Warren L. Robinson	62,400	2001-2003	86,112	172,224	344,448
Lester H. Loble, II	54,600	2001-2003	75,348	150,696	301,392

(1) Dividend equivalents were granted pursuant to the 1992 Key Employee Stock Option Plan and the 1997 Executive Long-Term Incentive Plan based on the number of options granted to each Named Officer (see Table 2). Dividend equivalents entitle the recipient to the cash amount equal to any dividend declared by the Board of Directors on the common stock of the Company. The table assumes the current level of dividends. Dividend equivalents may be earned from 0% to 200% at the end of the three year performance cycle (2001-2003) depending upon (1) the level of achievement of performance goals established for the Company and Montana-Dakota Utilities Co. and the utility services companies by the Compensation Committee and (2) individual performance. Vesting is accelerated upon a change in control. See Table 2 for a description of the goals. Dividend equivalents that are not earned are forfeited.

TABLE 5: PENSION PLAN TABLE

Remuneration	Years of Service 15	20	25	30	35
$125,000	$ 79,130	$ 87,626	$ 96,123	$104,619	$113,116
150,000	95,247	105,556	115,865	126,174	136,483
175,000	110,277	122,036	133,795	145,554	157,313
200,000	122,877	134,636	146,395	158,154	169,913
225,000	133,857	145,616	157,375	169,134	180,893
250,000	144,777	156,536	168,295	180,054	191,813
300,000	181,017	192,776	204,535	216,294	228,053
350,000	228,597	240,356	252,115	263,874	275,633
400,000	269,577	281,336	293,095	304,854	316,613
450,000	309,477	321,236	332,995	344,754	356,513
500,000	380,877	392,636	404,395	416,154	427,913

The Table covers the amounts payable under the Salaried Pension Plan and non-qualified Supplemental Income Security Plan (SISP).

Pension benefits are determined by the step-rate formula that places emphasis on the highest consecutive 60 months of earnings within the final 10 years of service.

Benefits for single participants under the Salaried Pension Plan are paid as straight life amounts and benefits for married participants are paid as actuarially reduced pensions with a survivorship benefit for spouses, unless participants choose otherwise.

The Salaried Pension Plan also permits pre-retirement survivorship benefits upon satisfaction of certain conditions. Additionally, certain reductions are made for employees electing early retirement.

The Internal Revenue Code places maximum limitations on benefit amounts that may be paid under the Salaried Pension Plan.

The Company has adopted a non-qualified SISP for senior management personnel. In 2001, 76 senior management personnel participated in the SISP, including the Named Officers.

Both plans cover salary shown in column (c) of the Summary Compensation Table and exclude bonuses and other forms of compensation.

Upon retirement and reaching age 65, participants in the SISP may elect a retirement benefit or a survivors' benefit with the benefits payable monthly for 15 years.

As of December 31, 2001, the Named Officers were credited with the following years of service under the plans:

Name	Pension Service Years	SISP Service Years
Martin A. White	10	10
Douglas C. Kane	30	20
Ronald D. Tipton	18	18
Warren L. Robinson	13	13
Lester H. Loble, II	14	14

The maximum years of service for benefits under the Pension Plan is 35. Vesting under the SISP begins at 3 years and is complete after 10 years. Benefit amounts under both plans are not subject to reduction for offset amounts.

CHANGE-OF-CONTROL ARRANGEMENTS

The Company entered into Change of Control Employment Agreements with the Named Officers in November 1998, which would become effective for a three-year period only upon a Company change of control. There is an automatic annual extension if the Company does not provide non-renewal notice at least 60 days prior to the end of each 12-month period.

If a change of control occurs, the agreements provide for a three-year employment period from the date they become effective, with base salary not less than the highest amount paid within the preceding twelve months, an annual bonus not less than the highest bonus paid within the preceding three years, and participation in the Company's incentive, savings, retirement and welfare benefit plans.

The agreements also provide that specified payments and benefits would be paid if the Named Officer's employment is terminated by the Company, other than for cause or disability, or by the Named Officer for good reason at any time when the agreements are in effect.

In such event, a Named Officer would receive an amount equal to three times his annual base pay plus three times his highest annual bonus (as defined). In addition, he would receive (i) an immediate pro-rated cash-out of his bonus for the year of termination based on the highest annual bonus and (ii) an amount equal to the excess of (a) the actuarial equivalent of the benefit under Company qualified and nonqualified retirement plans that he would receive if he continued employment with the Company for an additional three years over (b) the actual benefit paid or payable under these plans.

All benefits of each Named Officer under the Company's welfare benefit plans would continue for at least three years. These arrangements also provide for certain gross-up payments to compensate them for any excise taxes incurred in connection with these benefits and reimbursement for certain outplacement services.

For these purposes, "cause" means the Named Officer's willful and continued failure to substantially perform his duties or willfully engaging in illegal conduct or misconduct materially injurious to the Company. "Good reason" includes the Company's termination of the Named Officer without cause, the assignment to the Named Officer of duties inconsistent with his prior status and position, certain reductions in compensation or benefits, and relocation or increased travel obligations.

A "change of control" is defined as (i) the acquisition by a party or certain related parties of 20% or more of the Company's voting securities; (ii) a turnover in a majority of the Board of Directors without the approval of a majority of the members of the Board as of November 1998; (iii) a merger or similar transaction after which the Company's stockholders hold 60% or less of the voting securities of the surviving entity; or (iv) the stockholders' approval of the Company's liquidation or dissolution.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

Introduction

The Compensation Committee of the Board of Directors is responsible for determining the compensation of the Company's executive officers. Composed entirely of non-employee Directors, the Committee meets several times each year to review and determine compensation for the executive officers, including the Chief Executive Officer.

Executive Compensation

The Committee believes that appropriate compensation levels succeed in both attracting and motivating high quality employees. To implement this philosophy, the Committee analyzes trends in compensation among comparable companies participating in the oil and gas industry, segments of the energy and mining industries, the peer group of companies used in the graph following this report, and similar companies from general industry. The Committee then sets compensation levels that it believes are competitive within the industry and structured in a manner that rewards successful job performance. There are three components of total executive compensation: base salary, annual incentive compensation, and long-term incentive compensation.

In setting base salaries, the Committee does not use a particular formula. In addition to the above data, other factors the Committee uses in its analysis include the executive's current salary in comparison to the competitive industry standard as well as individual performance. Because of changing Mr. White's salary review from mid-year to a calendar year basis to coincide with the salary reviews of the other Named Officers, Mr. White, the Chairman, President and Chief Executive Officer, received no increase in base salary for 2001. The increase in salary shown in the Summary Compensation Table reflects a full year at Mr. White's salary set in August 2000. During 2001, only approximately 27.1% of Mr. White's compensation was base pay. The remainder was performance-based. This reflects the Committee's belief in the importance of having substantial at risk compensation to provide a direct and strong link between performance and executive pay. For the other Named Officers, the Committee targeted salaries at the midpoint of the competitive industry standard, rather than at 95% of the midpoint, as in the past. The other Named Officers received base salary increases averaging 16.20% for 2001.

In keeping with the Committee's belief that compensation should be directly linked to successful performance, the Company employs both annual and long-term incentive compensation plans. The annual incentive compensation is determined under the Executive Incentive Compensation Plan. The Committee makes awards based upon the level of corporate earnings, cost efficiency, and individual performance. Mr. White received a total of $374,500 (or 149.8% of the targeted amount) in annual incentive compensation for 2001; the other Named Officers received an average of $132,318 or 149.0% of the targeted amount, (except Mr. Tipton who received $35,437 or 40% of the targeted amount), based upon achievement of corporate earnings and individual performance near the maximum level.

Long-term incentive compensation serves to encourage successful strategic management and is awarded under two plans: the 1992 Key Employee Stock Option Plan and the 1997 Executive Long-Term Incentive Plan. Options granted in

1998 vested in full in 2000 based upon achievement of performance goals at the maximum level for the 1998-2000 performance cycle. In support of the Company's reward philosophy and to maintain alignment with marketplace practice, the Committee granted new stock options and dividend equivalents in 2001 to continue to motivate executives to achieve long-term corporate performance goals and to encourage ownership by them of Company Common Stock. Options with a three-year performance cycle (2001-2003) and related dividend equivalents were granted to Mr. White, the other Named Officers, and certain other executives in 2001 under the 1992 Key Employee Stock Option Plan (KESOP), using up the remaining KESOP reserve balance, with the remainder being granted under the 1997 Executive Long-Term Incentive Plan. The options become exercisable automatically in nine years, but vesting may be accelerated if certain performance goals are achieved. The size of awards is based upon an executive's established pay grade, which takes into consideration the job's internal value, based on overall complexity and responsibility, and external value as reflected in a market competitiveness comparison.

All regular employees participate in the growth of the Company through the Option Award Program. Stock options were granted under this program to all employees in 1998.

At December 31, 2001, there were approximately 3.5 million options outstanding under the Company's various plans, which is approximately 5% of shares outstanding.

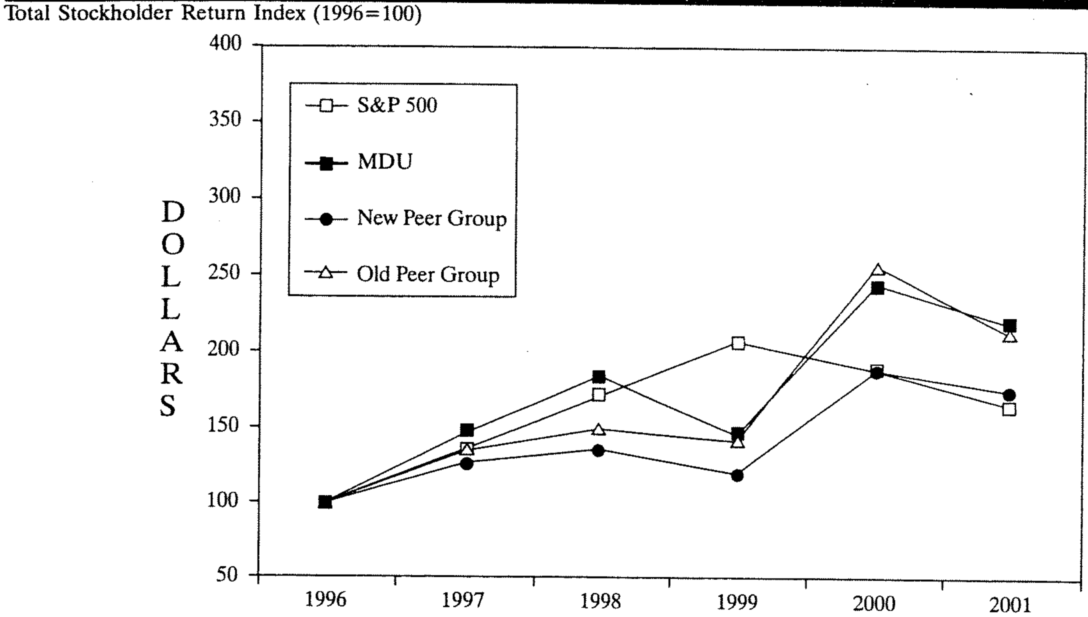
Restricted stock awards also were made in 2001 to Mr. White and the other Named Officers under the 1997 Executive Long-Term Incentive Plan. The restricted stock is performance accelerated; it vests automatically within nine years; however, vesting may be accelerated if total stockholder return on Company Common Stock meets or exceeds the 50th percentile of the peer group (as shown in the performance graph). The number of shares granted was to raise overall compensation levels closer to the median (although still slightly below) level of compensation within the industry. The restricted stock serves to motivate long-term performance and to align the interests of the executives with those of stockholders. The Committee accelerated vesting of one half of the restricted stock granted in 1999, based on achievement of performance goals for the three-year period 1999-2001 at the 49th percentile.

In 1994, the Board of Directors adopted Stock Ownership Guidelines under which executives are required to own Company Common Stock valued from one to four times their annual salary.

The 2001 compensation paid to the Company's executive officers qualified as fully deductible under federal tax laws. The Committee continues to monitor the impact of federal tax laws on executive compensation, including Section 162(m) of the Internal Revenue Code.

Harry J. Pearce, Chairman
Thomas Everist, Member
Homer A. Scott, Member

MDU RESOURCES GROUP, INC.
COMPARISON OF FIVE YEAR TOTAL STOCKHOLDER RETURN (1)



	1996	1997	1998	1999	2000	2001
S&P 500	100.00	133.36	171.48	207.56	188.66	166.24
MDU	100.00	143.63	184.87	145.84	245.15	219.02
New Peer Group	100.00	124.50	135.98	119.46	189.20	175.11
Old Peer Group	100.00	131.56	149.39	141.83	252.73	212.39

(1) All data is indexed to December 31, 1996, for the Company, the S&P 500, and the peer groups. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group is weighted according to the issuer's stock market capitalization at the beginning of the period.

New Peer Group issuers are Allegheny Energy, Inc., Allete, Inc., Alliant Energy Corporation, Black Hills Corporation, Comstock Resources, Inc., Equitable Resources, Inc., Florida Rock Industries, Inc., Hanson PLC ADR, KeySpan Corporation (returns included for the full years of trading for 1999 through 2001), Kinder Morgan, Inc., Louis Dreyfus Natural Gas Corp. (returns included for the full years of trading for 1997 through 2000. Discontinued trading in 2001, the result of the acquisition by Dominion Resources, Inc.), Martin Marietta Materials, Inc., Newfield Exploration Company, NICOR, Inc., OGE Energy Corp., ONEOK, Inc., Peoples Energy Corporation, Pogo Producing Company, Quanta Services, Inc. (returns included for the full years of trading for 1999 through 2001), Questar Corporation, SCANA Corporation, Stone Energy Corporation, TECO Energy, Inc., UGI Corporation, Vectren Corporation (formerly Indiana Energy, Inc.), Vulcan Materials Company, and XTO Energy, Inc.(formerly Cross Timbers Oil Company).

Old Peer Group issuers are Allete, Inc., Black Hills Corporation, Coastal Corporation (merged with El Paso Corporation in 2001. Returns included for years 1997 through 2000), Equitable Resources, Inc., LG&E Energy Corp. (discontinued trading on December 11, 2000 as a result of merger with Powergen PLC. Returns included for years 1997 through date of merger), The Montana Power Company, NorthWestern Corporation, ONEOK, Inc., Otter Tail Corporation (formerly Otter Tail Power Company), Questar Corporation and UGI Corporation.

The peer group was changed to include issuers that better reflect the Company's mix of regulated and unregulated businesses.

BALANCE SHEET

Year: 2001

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	Utility Plant				
3	101	Gas Plant in Service	$191,285,737	$197,090,940	3.03%
4	101.1	Property Under Capital Leases			
5	102	Gas Plant Purchased or Sold			
6	104	Gas Plant Leased to Others	29,961	25,772	-13.98%
7	105	Gas Plant Held for Future Use			
8	105.1	Production Properties Held for Future Use			
9	106	Completed Constr. Not Classified - Gas			
10	107	Construction Work in Progress - Gas	1,653,150	5,669,666	242.96%
11	108	(Less) Accumulated Depreciation	(117,484,590)	(123,988,907)	5.54%
12	111	(Less) Accumulated Amortization & Depletion	(505,958)	(518,667)	2.51%
13	114	Gas Plant Acquisition Adjustments	13,942,794	13,942,794	
14	115	(Less) Accum. Amort. Gas Plant Acq. Adj.	(171,642)	(517,780)	201.66%
15	116	Other Gas Plant Adjustments			
16	117	Gas Stored Underground - Noncurrent	1,195,374	2,795,330	133.85%
17	118	Other Utility Plant	609,335,488	616,121,210	1.11%
18	119	Accum. Depr. and Amort. - Other Utl. Plant	(329,835,124)	(347,258,370)	5.28%
19		**TOTAL Utility Plant**	$369,445,190	$363,361,988	-1.65%
20	**Other Property & Investments**				
21	121	Nonutility Property	$133,220	$140,013	5.10%
22	122	(Less) Accum. Depr. & Amort. of Nonutil. Prop.	(25,123)	(36,353)	44.70%
23	123	Investments in Associated Companies			
24	123.1	Investments in Subsidiary Companies	730,436,178	956,558,029	30.96%
25	124	Other Investments	24,559,856	25,822,974	5.14%
26	125	Sinking Funds			
27		**TOTAL Other Property & Investments**	$755,104,131	$982,484,663	30.11%
28	**Current & Accrued Assets**				
29	131	Cash	$7,072,666	$3,131,759	-55.72%
30	132-134	Special Deposits	1,200	1,200	
31	135	Working Funds	16,029	16,015	-0.09%
32	136	Temporary Cash Investments		1,906,817	100.00%
33	141	Notes Receivable			
34	142	Customer Accounts Receivable	47,495,868	22,175,582	-53.31%
35	143	Other Accounts Receivable	4,258,848	2,525,644	-40.70%
36	144	(Less) Accum. Provision for Uncollectible Accts.	(554,752)	(333,634)	-39.86%
37	145	Notes Receivable - Associated Companies			
38	146	Accounts Receivable - Associated Companies	11,279,658	12,316,880	9.20%
39	151	Fuel Stock	1,746,988	2,008,080	14.95%
40	152	Fuel Stock Expenses Undistributed			
41	153	Residuals and Extracted Products			
42	154	Plant Materials and Operating Supplies	6,288,886	5,758,377	-8.44%
43	155	Merchandise	960,692	911,650	-5.10%
44	156	Other Material & Supplies			
45	163	Stores Expense Undistributed			
46	164.1	Gas Stored Underground - Current	5,895,908	25,481,101	332.18%
47	165	Prepayments	7,533,214	9,371,438	24.40%
48	166	Advances for Gas Explor., Devl. & Production			
49	171	Interest & Dividends Receivable	10,811		-100.00%
50	172	Rents Receivable			
51	173	Accrued Utility Revenues	40,145,126	19,354,571	-51.79%
52	174	Miscellaneous Current & Accrued Assets	224,057	512,238	128.62%
53		**TOTAL Current & Accrued Assets**	$132,375,199	$105,137,718	-20.58%

BALANCE SHEET

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits (cont.)**			
2				
3	**Deferred Debits**			
4				
5	181 Unamortized Debt Expense	$1,392,023	$1,257,574	-9.66%
6	182.1 Extraordinary Property Losses			
7	182.2 Unrecovered Plant & Regulatory Study Costs			
	182.3 Other Regulatory Assets	3,838,483	3,470,463	-9.59%
	183 Prelim. Electric Survey & Investigation Chrg.	32,712	338,503	934.80%
8	183.1 Prelim. Nat. Gas Survey & Investigation Chrg.			
9	183.2 Other Prelim. Nat. Gas Survey & Invtg. Chrgs.			
10	184 Clearing Accounts	(167,067)	(22,715)	-86.40%
11	185 Temporary Facilities			
12	186 Miscellaneous Deferred Debits	5,017,758	14,177,327	182.54%
13	187 Deferred Losses from Disposition of Util. Plant			
14	188 Research, Devel. & Demonstration Expend.			
15	189 Unamortized Loss on Reacquired Debt	8,124,801	6,829,294	-15.95%
16	190 Accumulated Deferred Income Taxes	19,658,579	19,215,849	-2.25%
17	191 Unrecovered Purchased Gas Costs	(8,771,627)	(27,705,734)	215.86%
18	192.1 Unrecovered Incremental Gas Costs			
19	192.2 Unrecovered Incremental Surcharges			
20	**TOTAL Deferred Debits**	$29,125,662	$17,560,561	-39.71%
21				
22	**TOTAL ASSETS & OTHER DEBITS**	$1,286,050,182	$1,468,544,930	14.19%

	Account Number & Title	Last Year	This Year	% Change
23	**Liabilities and Other Credits**			
24				
25	**Proprietary Capital**			
26				
27	201 Common Stock Issued	$65,267,567	$70,016,851	7.28%
28	202 Common Stock Subscribed			
29	204 Preferred Stock Issued	16,500,000	16,400,000	-0.61%
30	205 Preferred Stock Subscribed			
31	207 Premium on Capital Stock	521,464,938	649,500,861	24.55%
32	211 Miscellaneous Paid-In Capital			
33	213 (Less) Discount on Capital Stock			
34	214 (Less) Capital Stock Expense	(2,694,284)	(2,980,351)	10.62%
35	216 Appropriated Retained Earnings	43,340,068	41,349,699	-4.59%
36	216.1 Unappropriated Retained Earnings	257,307,989	353,291,342	37.30%
37	217 (Less) Reacquired Capital Stock			
38	**TOTAL Proprietary Capital**	$901,186,278	$1,127,578,402	25.12%
39				
40	**Long Term Debt**			
41				
42	221 Bonds	$130,850,000	$130,850,000	
43	222 (Less) Reacquired Bonds			
44	223 Advances from Associated Companies			
45	224 Other Long Term Debt	43,043,971	27,500,000	-36.11%
46	225 Unamortized Premium on Long Term Debt			
47	226 (Less) Unamort. Discount on Long Term Debt-Dr.	(50,006)	(45,561)	-8.89%
48	**TOTAL Long Term Debt**	$173,843,965	$158,304,439	-8.94%

BALANCE SHEET

Year: 2001

	Account Number & Title		Last Year	This Year	% Change
1					
2	**Total Liabilities and Other Credits (cont.)**				
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Cap. Leases - Noncurrent			
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages	$1,195,672	$1,302,912	8.97%
9	228.3	Accumulated Provision for Pensions & Benefits	16,950,167	18,445,259	8.82%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds			
12		**TOTAL Other Noncurrent Liabilities**	$18,145,839	$19,748,171	8.83%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable	$8,000,000		-100.00%
17	232	Accounts Payable	34,769,716	15,329,149	-55.91%
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies	6,047,863	4,927,109	-18.53%
20	235	Customer Deposits	1,200,063	1,463,945	21.99%
21	236	Taxes Accrued	16,297,690	16,841,333	3.34%
22	237	Interest Accrued	2,319,289	2,256,546	-2.71%
23	238	Dividends Declared	14,422,621	16,108,133	11.69%
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	2,062,760	1,170,254	-43.27%
27	242	Miscellaneous Current & Accrued Liabilities	8,101,718	9,892,517	22.10%
28	243	Obligations Under Capital Leases - Current			
29		**TOTAL Current & Accrued Liabilities**	$93,221,720	$67,988,986	-27.07%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	$2,635,070	$1,702,961	-35.37%
34	253	Other Deferred Credits	4,373,350	3,642,062	-16.72%
35	254	Other Regulatory Liabilities	1,442,584	9,261,453	542.00%
36	255	Accumulated Deferred Investment Tax Credits	15,423,176	16,324,041	5.84%
37	256	Deferred Gains from Disposition Of Util. Plant			
38	257	Unamortized Gain on Reacquired Debt			
39	281-283	Accumulated Deferred Income Taxes	75,778,200	63,994,415	-15.55%
40		**TOTAL Deferred Credits**	$99,652,380	$94,924,932	-4.74%
41					
42	**TOTAL LIABILITIES & OTHER CREDITS**		$1,286,050,182	$1,468,544,930	14.19%

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NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 1

Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements of MDU Resources Group, Inc. and its subsidiaries (company) include the accounts of the following segments: electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production, and construction materials and mining. The electric and natural gas distribution segments and a portion of the pipeline and energy services segment are regulated. The company's nonregulated operations include the utility services, natural gas and oil production, and construction materials and mining segments, and a portion of the pipeline and energy services segment. For further descriptions of the company's business segments see Note 10. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generation stations.

The company's regulated businesses are subject to various state and federal agency regulation. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the company's nonregulated businesses.

The company's regulated businesses account for certain income and expense items under the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Regulation" (SFAS No. 71). SFAS No. 71 requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items is generally based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 2 for more information regarding the nature and amounts of these regulatory deferrals.

Prior to the sale of the company's coal operations as discussed in Note 10, intercompany coal sales, which were made at prices approximately the same as those charged to others, and the related utility fuel purchases are not eliminated in accordance with the provisions of SFAS No. 71. All other significant intercompany balances and transactions have been eliminated in consolidation.

Allowance for doubtful accounts

The company's allowance for doubtful accounts as of December 31, 2001 and 2000, was $5.8 million and $4.1 million, respectively.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost when first placed in service. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost and cost of removal, less salvage, is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for natural gas and oil production properties as described below, the resulting gains or losses are recognized as a component of income. The company is permitted to capitalize an allowance for funds used during construction (AFUDC) on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $6.6 million, $5.2 million and $1.7 million in 2001, 2000 and 1999, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for natural gas and oil production properties as described below.

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Goodwill and other intangible assets
The excess of the cost over the fair value of net assets of purchased businesses is recorded as goodwill and was being amortized on a straight-line basis over estimated useful lives for recorded goodwill in place at June 30, 2001. However, Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), which the company adopted as of January 1, 2002, as discussed later in Note 1, requires the discontinuance of goodwill amortization for the company's recorded goodwill at June 30, 2001, on January 1, 2002. Goodwill acquired after June 30, 2001, was subject immediately to the nonamortization provisions of SFAS No. 142.

Goodwill, net of accumulated amortization, was $174.2 million and $91.4 million as of December 31, 2001 and 2000, respectively. Goodwill is included in deferred charges and other assets. Goodwill amortization expense was $4.8 million, $7.0 million and $2.0 million for 2001, 2000 and 1999, respectively.

Impairment of long-lived assets and intangibles
The company reviews the carrying values of its long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and annually for goodwill as required by SFAS No. 142. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In 2000, the company experienced significant changes in market conditions at one of its energy marketing operations, which negatively affected the fair value of the assets at that operation. Due to the significance of the decline, the company recorded an impairment charge against goodwill of $3.9 million after-tax in 2000. The amount related to this impairment is included in depreciation, depletion and amortization. Excluding this impairment, no other long-lived assets or intangibles have been impaired and accordingly, no other impairment losses have been recorded in 2001, 2000 and 1999. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Impairment testing of natural gas and oil properties
The company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units of production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net revenues of proved reserves based on single point in time spot market prices, as mandated under the rules of the Securities and Exchange Commission, and the lower of cost or fair value of unproved properties. Future net revenue is estimated based on end-of-quarter spot market prices adjusted for contracted price changes. If capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter unless subsequent price changes eliminate or reduce an indicated write-down.

Due to abnormally low spot natural gas prices that existed on the last trading day of the third quarter of 2001, the company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at September 30, 2001. The lower natural gas prices were largely attributable to a sharp decline in nationwide spot market prices, especially natural gas prices in the Rocky Mountain region, over a relatively short period of time following the terrorist attacks on New York and Washington, D.C. on September 11, 2001, and prior to October 1, 2001. Oil prices likewise experienced a sharp drop during this same period. The company believes the decline in natural gas prices did not reflect

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NOTES TO FINANCIAL STATEMENTS (Continued)

the economics of its production assets in that natural gas prices actually being received by the company at the end of the third quarter of 2001 were significantly higher than the spot market prices at that time. In addition, historic natural gas prices have also generally been much higher and only a small portion of the company's natural gas is sold using spot market pricing. As of September 30, 2001, the capitalized costs exceeded the full-cost ceiling and would have resulted in a write-down of the company's natural gas and oil properties in the amount of approximately $32 million after-tax. However, subsequent to September 30, 2001, natural gas prices both nationwide and in the Rocky Mountain region increased significantly, thereby eliminating the need for a write-down of the company's natural gas and oil producing properties.

At December 31, 2001, the company's full-cost ceiling exceeded the company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2001, could result in a future write-down of the company's natural gas and oil properties.

Natural gas in underground storage
Natural gas in underground storage for the company's regulated operations is carried at cost using the last-in, first-out method. The portion of the cost of natural gas in underground storage expected to be used within one year is included in inventories and amounted to $28.6 million and $11.0 million at December 31, 2001 and 2000, respectively. The remainder of natural gas in underground storage is included in property, plant and equipment and was $43.1 million and $43.6 million at December 31, 2001 and 2000, respectively.

Inventories
Inventories, other than natural gas in underground storage for the company's regulated operations, consist primarily of materials and supplies of $22.5 million and $20.4 million, aggregates held for resale of $31.1 million and $22.7 million and other inventories of $13.1 million and $9.9 million as of December 31, 2001 and 2000, respectively. These inventories are stated at the lower of average cost or market.

Revenue recognition
Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is probable. The company recognizes utility revenue each month based on the services provided to all utility customers during the month. The company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed below. The company recognizes revenue from natural gas and oil production activities only on that portion of production sold and allocable to the company's ownership interest in the related well. The company generally recognizes all other revenues when services are rendered or goods are delivered.

Percentage-of-completion method
The company recognizes construction contract revenue from fixed price and modified fixed price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. Costs in excess of billings on uncompleted contracts of $29.7 million and $13.9 million for the years ending December 31, 2001 and 2000, respectively, represents revenues recognized in excess of amounts billed and is included in accounts receivable. Billings in excess of costs on uncompleted contracts of $17.3 million and $8.0 million for the years ending December 31, 2001 and 2000, respectively, represents billings in excess of revenues recognized and are included in accounts payable. Also included in accounts receivable are amounts representing balances billed but not paid by customers under retainage provisions in contracts which amounted to $20.5 million and $13.7 million as of December 31, 2001 and 2000, respectively.

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Advertising
The company expenses advertising costs as incurred and the amount of advertising expense for the years 2001, 2000 and 1999, was $2.9 million, $2.0 million and $1.3 million, respectively.

Natural gas costs recoverable or refundable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the company is deferring natural gas commodity, transportation and storage costs which are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 24 months to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments amounted to $27.7 million and $8.8 million for the years ended December 31, 2001 and 2000, respectively, and are included in other accrued liabilities.

Income taxes
The company provides deferred federal and state income taxes on all temporary differences. Excess deferred income tax balances associated with the company's rate-regulated activities resulting from the company's adoption of SFAS No. 109, "Accounting for Income Taxes," have been recorded as a regulatory liability and are included in other accrued liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged customers in accordance with applicable regulatory procedures.

The company uses the deferral method of accounting for investment tax credits and amortizes the credits on electric and natural gas distribution plant over various periods which conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Earnings per common share
Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options and restricted stock grants. For the years ending December 31, 2001 and 1999, 150,630 shares and 76,500 shares, respectively, with an average exercise price of $36.86 and $23.44, respectively, attributable to the exercise of outstanding options were excluded from the calculation of diluted earnings per share because their effect was antidilutive. For the year ending December 31, 2000, there were no shares excluded from the calculation of diluted earnings per share. For the years ending December 31, 2001, 2000 and 1999, no adjustments were made to reported earnings in the computation of earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Use of estimates
The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as property depreciable lives, tax provisions, uncollectible accounts, environmental and other loss contingencies, accumulated provision for revenues subject to refund, costs on construction contracts, unbilled revenues and actuarially determined benefit costs. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

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Cash flow information
Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	2001	2000	1999
		(In thousands)	
Interest, net of amount capitalized	$42,267	$41,912	$30,772
Income taxes	$75,284	$30,930	$32,723

The company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Reclassifications
Certain reclassifications have been made in the financial statements for prior years to conform to the current presentation. Such reclassifications had no effect on net income or stockholders' equity as previously reported.

New accounting pronouncements
In June 2001, the Financial Accounting Standards Board (FASB) approved Statement of Financial Accounting Standards No. 141, "Business Combinations" (SFAS No. 141). SFAS No. 141 requires that all business combinations be accounted for using the purchase method of accounting. The use of the pooling-of-interest method of accounting for business combinations is prohibited. The provisions of SFAS No. 141 apply to all business combinations initiated after June 30, 2001. The company is accounting for business combinations after June 30, 2001, in accordance with SFAS No. 141.

In June 2001, the FASB approved SFAS No. 142. SFAS No. 142 changes the accounting for goodwill and intangible assets and requires that goodwill no longer be amortized but be tested for impairment at least annually at the reporting unit level in accordance with SFAS No. 142. Recognized intangible assets with determinable useful lives should be amortized over their useful life and reviewed for impairment in accordance with Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). The provisions of SFAS No. 142 are effective for fiscal years beginning after December 15, 2001, except for provisions related to the nonamortization and amortization of goodwill and intangible assets acquired after June 30, 2001, which were subject immediately to the provisions of SFAS No. 142. The company adopted SFAS No. 142 on January 1, 2002. The company ceased amortization of its recorded goodwill at June 30, 2001, on January 1, 2002. Goodwill at each reporting unit will be tested for impairment as of January 1, 2002. The company will perform this transitional goodwill impairment test within six months of the date of adoption of SFAS No. 142. However, the amounts used in the transitional goodwill impairment test shall be measured as of January 1, 2002. The company believes the adoption of the goodwill impairment provisions of SFAS No. 142 will not have a material effect on its financial position or results of operations.

In June 2001, the FASB approved Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for the recorded amount or incurs a gain or loss upon settlement. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The company will adopt SFAS No. 143 on January 1, 2003, but has not yet quantified the effects of adopting SFAS No. 143 on its financial position or results of operations.

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In August 2001, the FASB approved SFAS No. 144. SFAS No. 144 supersedes Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." SFAS No. 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a segment of a business. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001. The company adopted SFAS No. 144 on January 1, 2002. The adoption of SFAS No. 144 did not have an effect on the company's financial position or results of operations.

The company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), amended by Statement of Financial Accounting Standards No. 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133" and Statement of Financial Accounting Standards No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities" (all such statements hereinafter referred to as SFAS No. 133) on January 1, 2001. SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

SFAS No. 133 requires that as of the date of initial adoption, the difference between the fair market value of derivative instruments recorded on the balance sheet and the previous carrying amount of those derivative instruments be reported in net income or other comprehensive income (loss), as appropriate, as the cumulative effect of a change in accounting principle in accordance with APB 20, "Accounting Changes." On January 1, 2001, the company reported a net-of-tax cumulative-effect adjustment of $6.1 million in accumulated other comprehensive loss to recognize at fair value all derivative instruments that are designated as cash-flow hedging instruments, which the company reflected in earnings over the 12 months ended December 31, 2001. The transition to SFAS No. 133 did not have an effect on the company's net income at adoption.

Comprehensive income

Upon the adoption of SFAS No. 133 on January 1, 2001, the company recorded a cumulative-effect adjustment in accumulated other comprehensive income to recognize all derivative instruments designated as hedges at fair value. As of December 31, 2001, the company has recorded unrealized gains and losses on swap agreements in accordance with SFAS No. 133. These amounts are reflected in the Consolidated Statements of Common Stockholders' Equity. For additional information on the adoption of SFAS No. 133, see new accounting pronouncements in Note 1, and Note 3. For the years ended December 31, 2000 and 1999, comprehensive income equaled net income as reported.

NOTE 2

Regulatory Assets and Liabilities

The following table summarizes the individual components of unamortized regulatory assets and liabilities included in the accompanying Consolidated Balance Sheets as of December 31:

	2001	2000
	(In thousands)	
Regulatory assets:		
Deferred income taxes	$ 13,417	$ 263
Long-term debt refinancing costs	6,829	8,125
Plant costs	2,499	2,668

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Postretirement benefit costs	722	833
Other	5,929	7,052
Total regulatory assets	29,396	18,941
Regulatory liabilities:		
Natural gas costs refundable through rate adjustments	27,706	8,772
Taxes refundable to customers	12,318	11,656
Plant decommissioning costs	8,243	7,601
Reserves for regulatory matters	7,132	6,087
Deferred income taxes	5,661	3,554
Other	5,053	1,193
Total regulatory liabilities	66,113	38,863
Net regulatory position	$ (36,717)	$ (19,922)

As of December 31, 2001, substantially all of the company's regulatory assets, other than certain deferred income taxes, are being reflected in rates charged to customers and are being recovered over the next one to 15 years.

If, for any reason, the company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of SFAS No. 71 occurs.

NOTE 3
Derivative Instruments
As of December 31, 2001, the company held derivative instruments designated as cash flow hedging instruments. All derivative instruments are recognized on the Consolidated Balance Sheets at fair value.

Hedging activities
The cash flow hedging instruments in place at December 31, 2001, are comprised of natural gas and oil price swap agreements. The objective for holding the natural gas and oil price swap agreements is to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on the company's forecasted sales of natural gas and oil production. The company also entered into an interest rate swap agreement which expired in the fourth quarter of 2001. The objective for holding the interest rate swap agreement was to manage a portion of the company's interest rate risk on the forecasted issuance of fixed-rate debt under Centennial Energy Holdings, Inc.'s (Centennial), a direct wholly owned subsidiary of the company, commercial paper program. The company designated each of the natural gas and oil price swap agreements as a hedge of the forecasted sale of natural gas and oil production and designated the interest rate swap agreement as a hedge of the risk of changes in interest rates on the company's forecasted issuances of fixed-rate debt under Centennial's commercial paper program.

The company's policy allows the use of derivative instruments as part of an overall energy price and interest rate risk management program to efficiently manage and minimize commodity price and interest rate risk. The company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions and the company has procedures in place to monitor compliance with its policies. The company is exposed to credit-related losses in relation to hedged derivative instruments in the event of nonperformance by counterparties. The company has policies and procedures, which management believes minimize credit-risk exposure. These policies and procedures include an evaluation of potential counterparties' credit ratings, credit exposure limitations, settlement of natural gas and oil price swap agreements monthly and settlement of interest rate swap agreements within 90 days. Accordingly, the company does not anticipate any material effect to its financial position or results of operations as a

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result of nonperformance by counterparties.

Upon the adoption of SFAS No. 133, the company recorded the fair market value of the natural gas and oil price swap agreements on the company's Consolidated Balance Sheets. On an ongoing basis, the company adjusts its balance sheet to reflect the current fair market value of its swap agreements. The related gains or losses on these agreements are recorded in common stockholders' equity as a component of other comprehensive income (loss). At the date the underlying transaction occurs, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the year ended December 31, 2001, the company recognized the ineffectiveness of all cash flow hedges, which is included in operating revenues and interest expense for the natural gas and oil price swap agreements and the interest rate swap agreement, respectively. For the year ended December 31, 2001, the amount of ineffectiveness recognized was immaterial. For the year ended December 31, 2001, the company did not exclude any components of the derivative instruments' gain or loss from the assessment of hedge effectiveness and there were no reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in the line item in which the hedged item is recorded. As of December 31, 2001, the maximum length of time over which the company is hedging its exposure to the variability in future cash flows for forecasted transactions is 12 months and the company estimates that net gains of approximately $2.2 million will be reclassified from accumulated other comprehensive income into earnings, subject to changes in natural gas and oil market prices, within the 12 months between January 1, 2002 and December 31, 2002, as the hedged transactions affect earnings.

In the event a derivative instrument does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; or if the derivative instrument expires or is sold, terminated, or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting will be discontinued, and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income (loss) would be recognized immediately in earnings. The company's policy requires approval to terminate a hedge agreement prior to its original maturity.

Energy marketing

The company had entered into other derivative instruments that were not designated as hedges in its energy marketing operations. In the third quarter of 2001, the company sold the vast majority of its energy marketing operations. The derivative instruments entered into by these operations prior to the sale in the third quarter of 2001 were natural gas forward purchase and sale commitments. These commitments involved the purchase and sale of natural gas and related delivery of such commodity. These operations sought to match natural gas purchases and sales so that a margin was obtained on the transportation of such commodity as distinguished from earning a margin on changes in market prices. The net change in fair value representing unrealized gains and losses resulting from changes

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in market prices on these derivative instruments was reflected as operating revenues or purchased natural gas sold. Net unrealized gains and losses on these derivative instruments were not material for the years ended December 31, 2001, 2000 and 1999.

NOTE 4
Fair Value of Other Financial Instruments
The estimated fair value of the company's long-term debt and preferred stock subject to mandatory redemption is based on quoted market prices of the same or similar issues. The estimated fair value of the company's long-term debt and preferred stock subject to mandatory redemption at December 31 is as follows:

	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$ 794,794	$ 894,652	$ 747,761	$772,127
Preferred stock subject to mandatory redemption	$ 1,400	$ 940	$ 1,500	$ 927

The fair value of other financial instruments for which estimated fair value has not been presented is not materially different than the related carrying amount.

NOTE 5
Short-term Borrowings
The company has unsecured short-term lines of credit from a number of banks totaling $110 million at December 31, 2001. These line of credit agreements provide for bank borrowings against the lines and/or support for commercial paper issues. The agreements provide for commitment fees at varying rates. There were no amounts outstanding on the short-term lines of credit at December 31, 2001. The amount outstanding on the short-term lines of credit was $8 million at December 31, 2000. The weighted average interest rate for borrowings outstanding at December 31, 2000, was 6.6 percent.

NOTE 6
Long-term Debt and Indenture Provisions
Long-term debt outstanding at December 31 is as follows:

	2001	2000
	(In thousands)	
First mortgage bonds and notes:		
Pollution Control Refunding Revenue Bonds, Series 1992, 6.65%, due June 1, 2022	$ 20,850	$ 20,850
Secured Medium-Term Notes, Series A at a weighted average rate of 7.59%, due on dates ranging from October 1, 2004 to April 1, 2012	110,000	110,000
Total first mortgage bonds and notes	130,850	130,850
Senior notes at a weighted average rate of 7.34%, due on dates ranging from July 31, 2002 to October 30, 2018	405,200	294,300
Commercial paper at a weighted average rate of 2.43%, supported by a revolving credit agreement	219,700	261,350
Revolving line of credit, 4.75%, due December 31, 2003	25,000	46,302

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Term credit agreements at a weighted average rate of 7.38%, due on dates ranging from February 1, 2002 through December 1, 2013	11,769	12,731
Pollution control note obligation, 6.20%, due March 1, 2004	2,500	2,800
Discount	(225)	(572)
Total long-term debt	794,794	747,761
Less current maturities	11,085	19,595
Net long-term debt	$ 783,709	$ 728,166

Centennial has a revolving credit agreement with various banks that supports Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreement at December 31, 2001. Under the commercial paper program, $219.7 million and $261.4 million were outstanding at December 31, 2001 and 2000, respectively. The commercial paper borrowings are classified as long term as Centennial intends to refinance these borrowings on a long-term basis through continued commercial paper borrowings and as further supported by the revolving credit agreement, which allows for subsequent borrowings up to a term of one year. Centennial intends to renew this existing credit agreement, which expires September 27, 2002, on an annual basis.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $300 million. Under the master shelf agreement, $210 million was outstanding at December 31, 2001, and $150 million was outstanding at December 31, 2000. The amount outstanding is included in senior notes in the preceding long-term debt table.

Under a revolving line of credit, the company has $40 million available as of December 31, 2001. The amount outstanding under the revolving line of credit was $25.0 million at December 31, 2001. At December 31, 2000, the company had $46.3 million outstanding under revolving lines of credit.

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2001, aggregate $11.1 million in 2002; $266.8 million in 2003; $21.9 million in 2004; $70.2 million in 2005; $85.2 million in 2006 and $339.6 million thereafter.

Substantially all of the company's electric and natural gas distribution properties, with certain exceptions, are subject to the lien of its Indenture of Mortgage. Under the terms and conditions of the Indenture, the company could have issued approximately $305 million of additional first mortgage bonds at December 31, 2001. Certain other debt instruments of the company contain restrictive covenants, all of which the company is in compliance with at December 31, 2001.

NOTE 7
Preferred Stocks
Preferred stocks at December 31 are as follows:

	2001	2000
	(Dollars in thousands)	
Authorized:		
Preferred --		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A --		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference --		
500,000 shares, cumulative, without par		

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value, issuable in series (none outstanding)		
Outstanding:		
Subject to mandatory redemption --		
Preferred --		
5.10% Series -- 14,000 shares in 2001 and 15,000 shares in 2000	$ 1,400	$ 1,500
Other preferred stock --		
4.50% Series -- 100,000 shares	10,000	10,000
4.70% Series -- 50,000 shares	5,000	5,000
	15,000	15,000
Total preferred stocks	16,400	16,500
Less sinking fund requirements	100	100
Net preferred stocks	$ 16,300	$ 16,400

The preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the company with certain limitations on 30 days notice on any quarterly dividend date on certain series of preferred stock.

The company is obligated to make annual sinking fund contributions to retire the 5.10% Series preferred stock. The redemption prices and sinking fund requirements, where applicable, are summarized below:

Series	Redemption Price (a)	Sinking Fund Shares	Sinking Fund Price (a)
Preferred stocks:			
4.50%	$105 (b)	---	---
4.70%	$102 (b)	---	---
5.10%	$102	1,000 (c)	$100

(a) Plus accrued dividends.
(b) These series are redeemable at the sole discretion of the company.
(c) Annually on December 1, if tendered.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The aggregate annual sinking fund amount applicable to preferred stock subject to mandatory redemption is $100,000 for each of the five years following December 31, 2001, and $900,000 thereafter.

NOTE 8
Common Stock
At the Annual Meeting of Stockholders held in April 1999, the company's common stockholders approved an amendment to the Certificate of Incorporation increasing the authorized number of common shares from 75 million shares to 150 million shares and reducing the par value of the common stock from $3.33 per share to $1.00 per share.

The company's Automatic Dividend Reinvestment and Stock Purchase Plan (Stock Purchase Plan) provides participants the opportunity to invest all or a portion of their cash dividends in shares of the company's common stock and to make optional cash payments for the same purpose. Holders of all classes of the company's capital stock, legal residents in any of the 50 states, and beneficial owners, whose shares are held by brokers or other nominees through participation by their brokers or nominees, are eligible to participate in the Stock Purchase Plan. The company's 401(k) Retirement Plan (K-Plan), is funded with the company's common stock. Since January 1, 1999, the Stock Purchase Plan and K-Plan have been funded primarily by the purchase of shares of common stock on the open market, except from January 1, 1999 through March 31, 1999, when shares of authorized but unissued common stock were used to fund the Stock Purchase Plan. At December 31, 2001, there were 8.1 million shares of common stock reserved for original issuance under the Stock Purchase

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Plan and K-Plan.

In November 1998, the company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right (right) for each outstanding share of the company's common stock. Each right becomes exercisable, upon the occurrence of certain events, for one one-thousandth of a share of Series B Preference Stock of the company, without par value, at an exercise price of $125 per one one-thousandth, subject to certain adjustments. The rights are currently not exercisable and will be exercisable only if a person or group (acquiring person) either acquires ownership of 15 percent or more of the company's common stock or commences a tender or exchange offer that would result in ownership of 15 percent or more. In the event the company is acquired in a merger or other business combination transaction or 50 percent or more of its consolidated assets or earnings power are sold, each right entitles the holder to receive, upon the exercise thereof at the then current exercise price of the right multiplied by the number of one one-thousandth of a Series B Preference Stock for which a right is then exercisable, in accordance with the terms of the rights agreement, such number of shares of common stock of the acquiring person having a market value of twice the then current exercise price of the right. The rights, which expire on December 31, 2008, are redeemable in whole, but not in part, for a price of $.01 per right, at the company's option at any time until any acquiring person has acquired 15 percent or more of the company's common stock.

The company has stock option plans for directors, key employees and employees, which grant options to purchase shares of the company's stock. The company accounts for these option plans in accordance with APB Opinion No. 25 under which no compensation expense has been recognized. The option exercise price is the market value of the stock on the date of grant. Options granted to the key employees automatically vest after nine years, but the plan provides for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the company, and expire 10 years after the date of grant. Options granted to directors and employees vest at date of grant and three years after date of grant, respectively, and expire 10 years after the date of grant. In addition, the company has granted restricted stock awards under a long-term incentive plan, deferred compensation agreements and a restricted stock agreement totaling 350,392 shares, 348,021 shares and 105,250 shares in 2001, 2000 and 1999, respectively. The restricted stock awards granted vest to the participants at various times ranging from two years to nine years from date of issuance but certain grants may vest early based upon the attainment of certain performance goals or upon a change in control of the company. The weighted average grant date fair value of the restricted stock grants was $31.55, $20.81 and $22.91 in 2001, 2000 and 1999, respectively. Compensation expense recognized for restricted stock grants was $4.5 million, $1.6 million and $722,000 in 2001, 2000 and 1999, respectively. Under the stock option plans and long-term incentive plan, the company is authorized to grant options and restricted stock for up to 9.8 million shares of common stock and has granted options and restricted stock on 4.8 million shares through December 31, 2001.

Had the company recorded compensation expense for the fair value of options granted consistent with SFAS No. 123, "Accounting for Stock-Based Compensation," net income would have been reduced on a pro forma basis by $3.8 million in 2001, $529,000 in 2000, and $498,000 in 1999. On a pro forma basis, basic and diluted earnings per share for 2001 would have been reduced by $.06. On a pro forma basis, there would have been no effect on basic earnings per share for 2000, and diluted earnings per share would have been reduced by $.01. On a pro forma basis, basic and diluted earnings per share for 1999 would have been reduced by $.01.

A summary of the status of the stock option plans at December 31, 2001, 2000 and 1999, and changes during the years then ended are as follows:

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	2001		2000		1999	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	1,224,959	$20.61	1,427,262	$19.46	1,516,808	$19.17
Granted	2,693,120	30.14	74,000	20.54	22,500	23.31
Forfeited	(74,282)	27.24	(84,135)	21.18	(57,966)	20.38
Exercised	(371,590)	20.23	(192,168)	11.84	(54,080)	11.95
Balance at end of year	3,472,207	27.90	1,224,959	20.61	1,427,262	19.46
Exercisable at end of year	770,142	$21.41	129,763	$18.11	301,681	$13.89

Summarized information about stock options outstanding and exercisable as of December 31, 2001, is as follows:

	Options Outstanding			Options Exercisable	
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$10.50 - 17.50	41,966	3.7	$13.36	41,966	$13.36
17.51 - 24.50	789,371	6.3	21.15	698,176	21.16
24.51 - 31.50	2,490,240	9.2	29.74	---	---
31.51 - 38.55	150,630	9.2	36.86	30,000	38.55
	3,472,207			770,142	

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options are as follows:

	2001	2000	1999
Weighted average fair value of options at grant date	$ 7.38	$ 5.07	$ 4.82
Weighted average risk-free interest rate	5.19%	6.76%	5.98%
Weighted average expected price volatility	26.05%	23.55%	22.03%
Weighted average expected dividend yield	3.53%	3.84%	4.22%
Expected life in years	7	7	7

NOTE 9
Income Taxes
Income tax expense is summarized as follows:

Years ended December 31,	2001	2000 (In thousands)	1999
Current:			
Federal	$ 66,211	$ 27,865	$ 29,574
State	11,160	5,188	3,874
Foreign	(44)	67	158
	77,327	33,120	33,606
Deferred:			

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Income taxes --			
Federal	16,972	29,323	12,902
State	4,773	8,060	3,690
Investment tax credit	(731)	(853)	(888)
	21,014	36,530	15,704
Total income tax expense	$ 98,341	$ 69,650	$ 49,310

Components of deferred tax assets and deferred tax liabilities recognized in the company's Consolidated Balance Sheets at December 31 are as follows:

	2001	2000
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 21,000	$ 7,650
Accrued pension costs	9,349	10,325
Accrued land reclamation	1,648	1,941
Deferred investment tax credit	1,413	1,697
Other	21,691	18,213
Total deferred tax assets	55,101	39,826
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	302,103	264,635
Basis differences on natural gas and oil producing properties	61,684	36,763
Regulatory matters	5,661	3,554
Other	9,092	7,826
Total deferred tax liabilities	378,540	312,778
Net deferred income tax liability	$ (323,439)	$ (272,952)

The following table reconciles the change in the net deferred income tax liability from December 31, 2000, to December 31, 2001, to the deferred income tax expense included in the Consolidated Statements of Income:

	2001
	(In thousands)
Net change in deferred income tax liability from the preceding table	$ 50,487
Deferred taxes associated with acquisitions	(29,807)
Other	334
Deferred income tax expense for the period	$ 21,014

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference are as follows:

Years ended December 31,	2001 Amount	%	2000 Amount	%	1999 Amount	%
		(Dollars in thousands)				
Computed tax at federal statutory rate	$ 88,966	35.0	$ 63,237	35.0	$ 46,686	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	11,311	4.5	8,044	4.4	5,921	4.4
Investment tax credit amortization	(731)	(.3)	(853)	(.5)	(888)	(.6)
Depletion allowance	(1,820)	(.7)	(1,631)	(.9)	(1,300)	(1.0)
Other items	615	.2	853	.5	(1,109)	(.8)

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Total income tax expense	$ 98,341	38.7	$ 69,650	38.5	$ 49,310	37.0

NOTE 10

Business Segment Data

The company's reportable segments are those that are based on the company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation.

The company's operations are conducted through six business segments. Substantially all of the company's operations are located within the United States. The electric segment generates, transmits and distributes electricity and the natural gas distribution segment distributes natural gas. These operations also supply related value-added products and services in the northern Great Plains. The utility services segment consists of a diversified infrastructure company specializing in engineering, design and build capability for electric, gas and telecommunication utility construction, as well as industrial and commercial electrical, exterior lighting and traffic signalization throughout most of the United States. Utility services provides related specialty equipment manufacturing sales and rental services. The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. Energy-related marketing and management services as well as cable and pipeline locating services also are provided. The pipeline and energy services segment includes investments in domestic and international growth opportunities. The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration and production activities primarily in the Rocky Mountain region of the United States and in the Gulf of Mexico. The construction materials and mining segment mines aggregates and markets crushed stone, sand, gravel and other related construction materials, including ready-mixed concrete, cement and asphalt, as well as value-added products and services in the north central and western United States, including Alaska and Hawaii.

In 2001, the company sold its coal operations to Westmoreland Coal Company for $28.2 million in cash, including final settlement cost adjustments. The sale of the coal operations was effective April 30, 2001. Included in the sale were active coal mines in North Dakota and Montana, coal sales agreements, reserves and mining equipment, and certain development rights at the former Gascoyne Mine site in North Dakota. The company retains ownership of coal reserves and leases at its former Gascoyne Mine site. Including final settlement cost adjustments, the company recorded a gain of $10.3 million ($6.2 million after-tax) included in other income - net from the sale in 2001.

On August 30, 2001, MDU Resources International, Inc. (MDU International), a wholly owned subsidiary of the company, through an indirect wholly owned Brazilian subsidiary, entered into a joint venture agreement with a Brazilian firm under which the parties have formed MPX Holdings, Ltda. (MPX) to develop electric generation and transmission, steam generation, power equipment, coal mining and construction materials projects in Brazil. MDU International has a 49 percent interest in MPX. MPX is currently developing, through a wholly owned subsidiary, and has under construction a 200-megawatt natural gas-fired power plant (Project) in the Brazilian state of Ceara. The Project is expected to enter commercial operation in the second quarter of 2002. MPX expects to enter into an agreement with Petrobras, the state-controlled energy company, under which Petrobras would purchase all of the capacity and market all of the Project's energy. Petrobras would also supply natural gas to the Project when energy is dispatched. The Project has a total estimated construction cost of approximately $96 million. At December 31, 2001, MDU International's investment in the Project was approximately $23.8 million. In addition, the company's subsidiaries had guaranteed Project obligations and loans for approximately $17.3 million as of December 31, 2001.

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Segment information follows the same accounting policies as described in the Summary of Significant Accounting Policies. Segment information included in the accompanying Consolidated Balance Sheets as of December 31 and included in the Consolidated Statements of Income for the years then ended is as follows:

	2001	2000 (In thousands)	1999
External operating revenues:			
Electric	$ 168,837	$ 161,621	$ 154,869
Natural gas distribution	255,389	233,051	157,692
Utility services	364,746	169,382	99,917
Pipeline and energy services	479,108	579,207	334,188
Natural gas and oil production	148,653	99,014	63,238
Construction materials and mining	801,883	617,564	455,939
Total external operating revenues	$ 2,218,616	$ 1,859,839	$ 1,265,843
Intersegment operating revenues:			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	4	---	---
Pipeline and energy services	52,006	57,641	49,344
Natural gas and oil production	61,178	39,302	15,156
Construction materials and mining(a)	5,016	13,832	13,966
Intersegment eliminations	(113,188)	(96,943)	(64,500)
Total intersegment operating revenues(a)	$ 5,016	$ 13,832	$ 13,966
Depreciation, depletion and amortization:			
Electric	$ 19,488	$ 19,115	$ 18,375
Natural gas distribution	9,337	8,399	7,348
Utility services	8,395	4,912	2,591
Pipeline and energy services	14,341	15,301	8,248
Natural gas and oil production	41,690	27,008	19,248
Construction materials and mining	46,666	36,153	26,008
Total depreciation, depletion and amortization	$ 139,917	$ 110,888	$ 81,818
Interest expense:			
Electric	$ 8,531	$ 10,007	$ 9,692
Natural gas distribution	3,727	4,142	3,614
Utility services	3,807	2,492	812
Pipeline and energy services	9,136	10,029	7,281
Natural gas and oil production	1,359	5,160	3,405
Construction materials and mining	19,339	16,415	11,202
Intersegment eliminations	---	(212)	---
Total interest expense	$ 45,899	$ 48,033	$ 36,006
Income taxes:			
Electric	$ 10,511	$ 10,048	$ 8,678
Natural gas distribution	1,067	3,544	1,443
Utility services	9,131	6,027	4,323
Pipeline and energy services	11,633	9,214	13,356
Natural gas and oil production	40,486	23,906	10,032
Construction materials and mining	25,513	16,911	11,478
Total income taxes	$ 98,341	$ 69,650	$ 49,310

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Earnings on common stock:			
Electric	$ 18,717	$ 17,733	$ 15,973
Natural gas distribution	677	4,741	3,192
Utility services	12,910	8,607	6,505
Pipeline and energy services	16,406	10,494	20,972
Natural gas and oil production	63,178	38,574	16,207
Construction materials and mining	43,199	30,113	20,459
Total earnings on common stock	$ 155,087	$ 110,262	$ 83,308
Capital expenditures:			
Electric	$ 14,373	$ 15,788	$ 18,218
Natural gas distribution	14,685	21,336	9,246
Utility services	70,232	42,633	16,052
Pipeline and energy services	51,054	69,006	35,123
Natural gas and oil production	118,719	173,441	64,294
Construction materials and mining	170,585	218,716	105,098
Net proceeds from sale or disposition of property	(51,641)	(11,000)	(16,660)
Total net capital expenditures	$ 388,007	$ 529,920	$ 231,371
Identifiable assets:			
Electric(b)	$ 291,229	$ 305,099	$ 307,417
Natural gas distribution(b)	182,705	192,854	131,294
Utility services	239,069	123,451	67,755
Pipeline and energy services	346,879	362,592	302,587
Natural gas and oil production	476,105	410,207	255,416
Construction materials and mining	1,035,929	874,299	655,499
Corporate assets(c)	51,155	44,457	46,335
Total identifiable assets	$ 2,623,071	$ 2,312,959	$ 1,766,303
Property, plant and equipment:			
Electric (b)	$ 597,080	$ 589,700	$ 581,090
Natural gas distribution (b)	238,566	227,742	185,797
Utility services	59,190	39,865	21,876
Pipeline and energy services	410,049	369,834	308,409
Natural gas and oil production	630,826	513,419	343,157
Construction materials and mining	820,984	755,563	601,952
Less accumulated depreciation, depletion and amortization	947,377	895,109	794,105
Net property, plant and equipment	$ 1,809,318	$ 1,601,014	$ 1,248,176

(a) In accordance with the provision of SFAS No. 71, intercompany coal sales are not eliminated.
(b) Includes, in the case of electric and natural gas distribution property, allocations of common utility property.
(c) Corporate assets consist of assets not directly assignable to a business segment (i.e., cash and cash equivalents, certain accounts receivable and other miscellaneous current and deferred assets).

Capital expenditures for 2001, 2000 and 1999, related to acquisitions, in the preceding table include the following noncash transactions: issuance of the company's equity securities of $57.4 million in 2001; issuance of the company's equity securities and the conversion of a note receivable to purchase consideration of $132.1 million in 2000; and issuance of the company's equity securities of $77.5 million in 1999.

NOTE 11
Acquisitions

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In 2001, the company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Hawaii, Minnesota and Oregon; utility services businesses based in Missouri and Oregon; and an energy services company specializing in cable and pipeline locating and tracking systems. The total purchase consideration for these businesses, consisting of the company's common stock and cash, was $170.1 million.

In 2000, the company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses with operations in Alaska, California, Montana and Oregon; a coalbed natural gas development operation based in Colorado with related oil and gas leases and properties in Montana and Wyoming; utility services businesses based in California, Colorado, Montana and Ohio; a natural gas distribution business serving southeastern North Dakota and western Minnesota; and an energy services company based in Texas. The total purchase consideration for these businesses, consisting of the company's common stock, cash and the conversion of a note receivable to purchase consideration, was $286.0 million.

On April 1, 2000, Fidelity Exploration & Production Company (Fidelity), an indirect wholly owned subsidiary of the company, purchased substantially all of the assets of Preston Reynolds & Co., Inc. (Preston), a coalbed natural gas development operation, as previously discussed. Pursuant to the asset purchase and sale agreement, Preston may, but is not obligated to purchase, acquire and own an undivided 25 percent working interest (Seller's Option Interest) in certain oil and gas leases or properties acquired and/or generated by Fidelity. The Seller's Option Interest commences April 1, 2002 and terminates six months thereafter and requires Preston to pay Fidelity 25 percent of its capital investment, during the two year period subsequent to April 1, 2000, in the oil and gas leases or properties. Fidelity has the right, but not the obligation, to purchase Seller's Option Interest from Preston for an amount as specified in the agreement.

In 1999, the company acquired a number of businesses, none of which was individually material, including construction materials and mining companies with operations in California, Montana, Oregon and Wyoming; and utility services companies based in Montana and Oregon. The total purchase consideration for these businesses, consisting of the company's common stock and cash, was $81.9 million.

The above acquisitions were accounted for under the purchase method of accounting and accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. Final fair market values are pending the completion of the review of the relevant assets, liabilities and issues identified as of the acquisition date on certain of the above acquisitions made in 2001. The results of operations of the acquired businesses are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented as such acquisitions were not material to the company's financial position or results of operations.

NOTE 12
Employee Benefit Plans
The company has noncontributory defined benefit pension plans and other postretirement benefit plans. Changes in benefit obligation and plan assets for the years ended December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2001	2000	2001	2000
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at				

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beginning of year	$200,880	$180,997	$ 69,467	$ 65,939
Service cost	4,716	4,561	1,376	1,307
Interest cost	14,498	14,174	4,691	4,946
Plan participants' contributions	---	---	866	677
Amendments	(1,342)	7,111	---	---
Actuarial (gain) loss	8,128	9,535	(2,109)	928
Divestiture*	(10,017)	---	(2,871)	---
Benefits paid	(12,817)	(15,498)	(4,401)	(4,330)
Benefit obligation at end of year	204,046	200,880	67,019	69,467
Change in plan assets:				
Fair value of plan assets at beginning of year	261,864	276,459	47,046	47,147
Actual return on plan assets	(13,828)	875	(2,235)	(1,078)
Employer contribution	337	28	3,899	4,630
Plan participants' contributions	---	---	866	677
Divestiture*	(10,889)	---	---	---
Benefits paid	(12,817)	(15,498)	(4,401)	(4,330)
Fair value of plan assets at end of year	224,667	261,864	45,175	47,046
Funded status	20,621	60,984	(21,844)	(22,421)
Unrecognized actuarial gain	(26,170)	(76,417)	(10,799)	(15,228)
Unrecognized prior service cost	10,278	16,271	---	---
Unrecognized net transition obligation (asset)	(2,195)	(3,387)	23,665	28,532
Prepaid (accrued) benefit cost	$ 2,534	$ (2,549)	$ (8,978)	$ (9,117)

* See Note 10 for more information on the sale of the company's coal operations.

Weighted average assumptions for the company's pension and other postretirement benefit plans as of December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2001	2000	2001	2000
Discount rate	7.25%	7.50%	7.25%	7.50%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	5.00%	5.00%	5.00%	5.00%

Health care rate assumptions for the company's other postretirement benefit plans as of December 31 are as follows:

	2001	2000
Health care trend rate	6.00%-7.00%	6.00%-7.50%
Health care cost trend rate - ultimate	5.00%-6.00%	5.00%-6.00%
Year in which ultimate trend rate achieved	1999-2004	1999-2004

Components of net periodic benefit cost for the company's pension and other postretirement benefit plans are as follows:

	Pension Benefits			Other Postretirement Benefits		
Years ended December 31,	2001	2000	1999	2001	2000	1999
			(In thousands)			
Components of net periodic						

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benefit cost:						
Service cost	$ 4,716	$ 4,561	$ 4,894	$ 1,376	$ 1,307	$ 1,451
Interest cost	14,498	14,174	12,573	4,691	4,946	4,720
Expected return on assets	(20,672)	(19,927)	(17,489)	(3,619)	(3,267)	(2,807)
Amortization of prior service cost	1,247	1,047	842	---	---	---
Recognized net actuarial gain	(2,687)	(2,907)	(995)	(930)	(799)	(200)
Settlement (gain) loss	(884)	(700)	---	15	---	---
Amortization of net transition obligation (asset)	(965)	(997)	(997)	2,227	2,378	2,377
Net periodic benefit cost (income)	(4,747)	(4,749)	(1,172)	3,760	4,565	5,541
Less amount capitalized	(391)	(397)	(87)	329	369	463
Net periodic benefit expense (income)	$ (4,356)	$ (4,352)	$(1,085)	$ 3,431	$ 4,196	$ 5,078

The company's other postretirement benefit plans include health care and life insurance benefits. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have the following effects at December 31, 2001:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 260	$ (229)
Effect on postretirement benefit obligation	$ 3,326	$ (2,906)

In addition to company-sponsored plans, certain employees are covered under multi-employer defined benefit plans administered by a union. Amounts contributed to the multi-employer plans were $19.9 million, $10.6 million and $6.8 million in 2001, 2000 and 1999, respectively.

The company has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that provides for defined benefit payments upon the employee's retirement or to their beneficiaries upon death for a 15-year period. Investments consist of life insurance carried on plan participants, which is payable to the company upon the employee's death. The cost of these benefits was $4.3 million, $3.5 million and $3.3 million in 2001, 2000 and 1999, respectively.

The company sponsors various defined contribution plans for eligible employees. Costs incurred by the company under these plans were $7.2 million in 2001, $6.1 million in 2000 and $4.4 million in 1999. The costs incurred in each year reflect additional participants as a result of business acquisitions.

NOTE 13
Jointly Owned Facilities

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The consolidated financial statements include the company's 22.7 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station and the Coyote Station, respectively. Each owner of the Big Stone and Coyote stations is responsible for financing its investment in the jointly owned facilities.

The company's share of the Big Stone Station and Coyote Station operating expenses is reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2001	2000
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 50,053	$ 50,029
Less accumulated depreciation	32,956	31,381
	$ 17,097	$ 18,648
Coyote Station:		
Utility plant in service	$ 122,436	$ 122,111
Less accumulated depreciation	67,414	63,741
	$ 55,022	$ 58,370

NOTE 14

Regulatory Matters and Revenues Subject To Refund

In December 1999, Williston Basin Interstate Pipeline Company (Williston Basin), an indirect wholly owned subsidiary of the company, filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. On May 9, 2001, the Administrative Law Judge issued an Initial Decision on Williston Basin's natural gas rate change application, which matter is currently pending before and subject to revision by the FERC.

Reserves have been provided for a portion of the revenues that have been collected subject to refund with respect to the pending regulatory proceeding. Williston Basin, in the fourth quarter of 2000, determined that reserves it had previously established for certain regulatory proceedings, prior to the proceeding filed in 1999, exceeded its expected refund obligation and, accordingly, reversed reserves and recognized in income $6.7 million after-tax. Williston Basin, in the second quarter of 1999, determined that reserves it had previously established in relation to a 1992 general natural gas rate change application and the 1995 general rate increase application exceeded its expected refund obligation and, accordingly, reversed reserves and recognized in income $4.4 million after-tax. Williston Basin believes that its remaining reserves are adequate based on its assessment of the ultimate outcome of the application filed in December 1999.

NOTE 15

Commitments and Contingencies

Litigation

In March 1997, 11 natural gas producers filed suit in North Dakota Southwest Judicial District Court (North Dakota District Court) against Williston Basin and the company. The natural gas producers had processing agreements with Koch Hydrocarbon Company (Koch). Williston Basin and the company had natural gas purchase contracts with Koch. The natural gas producers alleged they were entitled to damages for the breach of Williston Basin's and the company's contracts with Koch although no specific damages were stated. A similar suit was filed by Apache Corporation (Apache) and Snyder Oil Corporation (Snyder) in North Dakota Northwest Judicial District Court in December 1993. The North Dakota Supreme Court in December 1999 affirmed the North Dakota Northwest Judicial District Court decision dismissing Apache's and Snyder's claims against Williston Basin and the company. Based in part upon the decision of the North Dakota Supreme Court affirming the dismissal of the

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claims brought by Apache and Snyder, Williston Basin and the company filed motions for summary judgment to dismiss the claims of the 11 natural gas producers. The motions for summary judgment were granted by the North Dakota District Court in July 2000. On March 5, 2001, the North Dakota District Court entered a final judgment on the July 2000 order granting the motions for summary judgment. On May 4, 2001, the 11 natural gas producers appealed the North Dakota District Court's decision by filing a Notice of Appeal with the North Dakota Supreme Court. Oral argument was held before the North Dakota Supreme Court on December 12, 2001. Williston Basin and the company are awaiting a decision from the North Dakota Supreme Court.

In July 1996, Jack J. Grynberg (Grynberg) filed suit in United States District Court for the District of Columbia (U.S. District Court) against Williston Basin and over 70 other natural gas pipeline companies. Grynberg, acting on behalf of the United States under the Federal False Claims Act, alleged improper measurement of the heating content or volume of natural gas purchased by the defendants resulting in the underpayment of royalties to the United States. In March 1997, the U.S. District Court dismissed the suit without prejudice and the dismissal was affirmed by the United States Court of Appeals for the D.C. Circuit in October 1998. In June 1997, Grynberg filed a similar Federal False Claims Act suit against Williston Basin and Montana-Dakota Utilities Co. (Montana-Dakota) and filed over 70 other separate similar suits against natural gas transmission companies and producers, gatherers, and processors of natural gas. In April 1999, the United States Department of Justice decided not to intervene in these cases. In response to a motion filed by Grynberg, the Judicial Panel on Multidistrict Litigation consolidated all of these cases in the Federal District Court of Wyoming (Federal District Court). Oral argument on motions to dismiss was held before the Federal District Court in March 2000. On May 18, 2001, the Federal District Court denied Williston Basin's and Montana-Dakota's motion to dismiss. The matter is currently pending.

The Quinque Operating Company (Quinque), on behalf of itself and subclasses of gas producers, royalty owners and state taxing authorities, instituted a legal proceeding in State District Court for Stevens County, Kansas, (State District Court) against over 200 natural gas transmission companies and producers, gatherers, and processors of natural gas, including Williston Basin and Montana-Dakota. The complaint, which was served on Williston Basin and Montana-Dakota in September 1999, contains allegations of improper measurement of the heating content and volume of all natural gas measured by the defendants other than natural gas produced from federal lands. In response to a motion filed by the defendants in this suit, the Judicial Panel on Multidistrict Litigation transferred the suit to the Federal District Court for inclusion in the pretrial proceedings of the Grynberg suit. Upon motion of plaintiffs, the case has been remanded to State District Court. On September 12, 2001, the defendants in this suit filed a motion to dismiss with the State District Court. The matter is currently pending.

Williston Basin and Montana-Dakota believe the claims of Grynberg and Quinque are without merit and intend to vigorously contest these suits.

The company is also involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that there is no pending legal proceeding against or involving the company, except those discussed above, for which the outcome is likely to have a material adverse effect upon the company's financial position or results of operations.

Environmental matters

In December 2000, Morse Bros., Inc. (MBI), an indirect wholly owned subsidiary of the company, was named by the United States Environmental Protection Agency (EPA) as a Potentially Responsible Party in connection with the cleanup of a commercial property site, now owned by MBI, and part of the Portland, Oregon, Harbor Superfund Site. Sixty-eight other parties were also named in this administrative action. The EPA wants

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responsible parties to share in the cleanup of sediment contamination in the Willamette River. Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon State Department of Environmental Quality and other information available, MBI does not believe it is a Responsible Party. In addition, MBI intends to seek indemnity for any and all liabilities incurred in relation to the above matters from Georgia-Pacific West, Inc., the seller of the commercial property site to MBI, pursuant to the terms of their sale agreement.

Operating leases
The company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2001, are $17.4 million in 2002, $14.3 million in 2003, $11.0 million in 2004, $8.3 million in 2005, $6.3 million in 2006 and $25.1 million thereafter. Rent expense related to operating leases was approximately $31.5 million, $23.7 million and $15.4 million for the years ended December 31, 2001, 2000 and 1999, respectively.

Purchase commitments
The company has entered into various commitments, largely purchased-power, coal and natural gas supply, and natural gas transportation contracts. These commitments range from one to 17 years. The commitments under these contracts as of December 31, 2001, are $108.8 million in 2002, $53.1 million in 2003, $46.9 million in 2004, $39.2 million in 2005, $33.2 million in 2006 and $126.5 million thereafter. These commitments are not reflected in the company's consolidated financial statements.

Guarantees
The company has certain financial guarantees largely consisting of guarantees on obligations and loans on the natural gas-fired power plant project in the Brazilian state of Ceara. For more information on the natural gas-fired power plant project see Note 10. These guarantees, as of December 31, 2001, are approximately $20.6 million for 2002. These guarantees are not reflected in the consolidated financial statements.

NOTE 16
Quarterly Data (Unaudited)
The following unaudited information shows selected items by quarter for the years 2001 and 2000:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2001				
Operating revenues	$ 641,248	$ 546,418	$ 551,680	$ 484,286
Operating expenses	577,727	476,071	458,441	438,125
Operating income	63,521	70,347	93,239	46,161
Net income	32,687	43,417	50,746	28,999
Earnings per common share:				
Basic	.50	.64	.75	.42
Diluted	.49	.63	.74	.42
Weighted average common shares outstanding:				
Basic	65,405	67,264	67,650	68,729
Diluted	65,979	68,376	68,127	69,126
2000				
Operating revenues	$371,989	$362,979	$530,834	$607,869
Operating expenses	342,559	321,900	454,811	537,414
Operating income	29,430	41,079	76,023	70,455
Net income	13,364	21,126	39,992	36,546
Earnings per common share:				

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Basic	.23	.35	.63	.57
Diluted	.23	.35	.63	.56
Weighted average common shares outstanding:				
Basic	57,051	59,987	62,975	64,289
Diluted	57,188	60,212	63,345	64,817

Certain company operations are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

NOTE 17
Natural Gas and Oil Activities (Unaudited)
Fidelity is involved in the acquisition, exploration, development and production of natural gas and oil resources. Fidelity's activities include the acquisition of producing properties with potential development opportunities, exploratory drilling and the operation and development of natural gas production properties. Fidelity shares revenues and expenses from the development of specified properties located primarily in the Rocky Mountain region of the United States and in the Gulf of Mexico in proportion to its interests.

Fidelity owns in fee or holds natural gas leases for the properties it operates in Colorado, Montana, North Dakota and Wyoming. These rights are in the Bonny Field located in eastern Colorado, the Cedar Creek Anticline in southeastern Montana and southwestern North Dakota, the Bowdoin area located in north-central Montana and in the Powder River Basin of Wyoming and Montana.

The information that follows includes the company's proportionate share of all its natural gas and oil interests held by Fidelity.

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization related to natural gas and oil producing activities at December 31:

	2001	2000 (In thousands)	1999
Subject to amortization	$ 506,155	$ 416,881	$ 319,448
Not subject to amortization	122,354	94,856	23,464
Total capitalized costs	628,509	511,737	342,912
Less accumulated depreciation, depletion and amortization	195,469	155,198	129,211
Net capitalized costs	$ 433,040	$ 356,539	$ 213,701

Capital expenditures, including those not subject to amortization, related to natural gas and oil producing activities are as follows:

Years ended December 31,	2001	2000 (In thousands)	1999
Acquisitions	$ 1,695	$ 68,858	$ 30,842
Exploration	13,938	34,839	11,010
Development	102,670	69,051	21,822
Total capital expenditures	$ 118,303	$ 172,748	$ 63,674

The following summary reflects income resulting from the company's operations of natural gas and oil producing activities, excluding corporate overhead and financing costs:

Years ended December 31,	2001	2000 (In thousands)	1999

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Revenues	$ 203,727	$ 128,217	$ 75,327
Production costs	47,045	33,919	25,402
Depreciation, depletion and amortization	41,223	26,739	19,136
Pretax income	115,459	67,559	30,789
Income tax expense	45,245	25,835	11,815
Results of operations for producing activities	$ 70,214	$ 41,724	$ 18,974

The following table summarizes the company's estimated quantities of proved natural gas and oil reserves at December 31, 2001, 2000 and 1999, and reconciles the changes between these dates. Estimates of economically recoverable natural gas and oil reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

	2001 Natural Gas	2001 Oil	2000 Natural Gas	2000 Oil	1999 Natural Gas	1999 Oil
	(In thousands of Mcf/barrels)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	309,800	15,100	268,900	14,700	243,600	11,500
Production	(40,600)	(2,000)	(29,200)	(1,900)	(24,700)	(1,800)
Extensions and discoveries	66,400	2,000	51,300	1,600	21,800	800
Purchases of proved reserves	1,000	100	23,200	100	38,200	700
Sales of reserves in place	---	---	---	(100)	(9,300)	(400)
Revisions to previous estimates due to improved secondary recovery techniques and/or changed economic conditions	(12,500)	2,300	(4,400)	700	(700)	3,900
Balance at end of year	324,100	17,500	309,800	15,100	268,900	14,700

Proved developed reserves:		
January 1, 1999	193,000	10,700
December 31, 1999	213,400	13,300
December 31, 2000	263,400	14,200
December 31, 2001	291,300	17,100

All of the company's interests in natural gas and oil reserves are located in the United States and in the Gulf of Mexico.

The standardized measure of the company's estimated discounted future net cash flows of total proved reserves associated with its various natural gas and oil interests at December 31 is as follows:

	2001	2000	1999
	(In thousands)		
Future net cash flows before income taxes	$ 548,000	$ 2,349,500	$ 492,000
Future income tax expense	112,000	827,000	131,500
Future net cash flows	436,000	1,522,500	360,500

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10% annual discount for estimated timing of cash flows	174,000	601,200	131,400
Discounted future net cash flows relating to proved natural gas and oil reserves	$ 262,000	$ 921,300	$ 229,100

The following are the sources of change in the standardized measure of discounted future net cash flows by year:

	2001	2000	1999
		(In thousands)	
Beginning of year	$ 921,300	$ 229,100	$ 125,100
Net revenues from production	(153,500)	(94,300)	(49,900)
Change in net realization	(1,119,700)	861,700	123,100
Extensions, discoveries and improved recovery, net of future production-related costs	64,200	288,700	33,500
Purchases of proved reserves	2,600	93,200	57,700
Sales of reserves in place	---	(1,500)	(14,700)
Changes in estimated future development costs, net of those incurred during the year	(3,300)	3,400	(9,800)
Accretion of discount	126,900	31,200	16,700
Net change in income taxes	436,500	(412,300)	(59,800)
Revisions of previous quantity estimates	(11,700)	(79,200)	7,400
Other	(1,300)	1,300	(200)
Net change	(659,300)	692,200	104,000
End of year	$ 262,000	$ 921,300	$ 229,100

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using year-end natural gas prices and oil prices. Future development and production costs attributable to proved reserves were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future income tax expenses were computed by applying statutory tax rates (adjusted for permanent differences and tax credits) to estimated net future pretax cash flows.

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of natural gas and oil properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. In addition, future realization of natural gas and oil prices over the remaining reserve lives may vary significantly from current prices.

NOTE 18

Subsequent Event

In January 2002, Fidelity Oil Co. (FOC), one of the company's natural gas and oil production subsidiaries, entered into a compromise agreement with the former operator of certain of FOC's oil production properties in southeastern Montana. The compromise agreement resolved litigation involving the interpretation and application of contractual provisions regarding net proceeds interests paid by the former operator to FOC for a number of years prior to 1998. The terms of the compromise agreement are confidential. As a result of the compromise agreement, the natural gas and oil production segment will reflect a nonrecurring gain in its financial results for the first quarter of 2002 of approximately $16.6 million after-tax. As part of the settlement, FOC gave the former operator a full and complete release, and FOC is not asserting any such claim against the former operator for periods after 1997.

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NOTE 19
Investment in Subsidiaries
The Respondent owns two wholly owned subsidiaries, Centennial Energy Holdings, Inc. and MDU Resources International, Inc. Centennial Energy Holdings, Inc. owns WBI Holdings, Inc., Knife River Corporation and Utility Services, Inc.

As required by the Federal Energy Regulatory Commission for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investment using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary, as required by generally accepted accounting principles. If generally accepted accounting principles were followed, utility plant, other property and investments would increase by $501,669,316 and $517,845,533; current and accrued assets would increase by $376,353,971 and $347,911,277; deferred debits would increase by $276,502,929 and $161,152,427; preferred stock would decrease by $100,000 and $100,000; long-term debt would increase by $625,404,164 and $554,322,288; other noncurrent liabilities and current and accrued liabilities would increase by $157,590,276 and $173,105,095; deferred credits would increase by $373,039,122 and $303,207,667 as of December 31, 2001 and 2000, respectively. Furthermore, operating revenues would increase by $1,799,405,574 and $1,478,998,298; and operating expenses, excluding income taxes, would increase by $1,568,444,117 and $1,310,284,540 for the year ended December 31, 2001 and 2000, respectively. In addition, net cash provided by operating activities would increase by $275,732,000; net cash used in investing activities would increase by $225,841,000; net cash provided by financing activities would decrease by $42,558,000; and the net change in cash and cash equivalents would be an increase of $7,333,000 for the year ended December 31, 2001. Reporting its subsidiary investment using the equity method rather than generally accepted accounting principles has no effect on net income or retained earnings.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2001

	Account Number & Title		Last Year	This Year	% Change
1	**Intangible Plant**				
2					
3	301	Organization			
4	302	Franchises & Consents			
5	303	Miscellaneous Intangible Plant	$1,432,789	$1,525,858	6.50%
6					
7	**TOTAL Intangible Plant**		$1,432,789	$1,525,858	6.50%
8					
9	**Production Plant**				
10					
11	Production & Gathering Plant				
12					
13	325.1	Producing Lands			
14	325.2	Producing Leaseholds			
15	325.3	Gas Rights			
16	325.4	Rights-of-Way			
17	325.5	Other Land & Land Rights			
18	326	Gas Well Structures			
19	327	Field Compressor Station Structures			
20	328	Field Meas. & Reg. Station Structures			
21	329	Other Structures		NOT	
22	330	Producing Gas Wells-Well Construction		APPLICABLE	
23	331	Producing Gas Wells-Well Equipment			
24	332	Field Lines			
25	333	Field Compressor Station Equipment			
26	334	Field Meas. & Reg. Station Equipment			
27	335	Drilling & Cleaning Equipment			
28	336	Purification Equipment			
29	337	Other Equipment			
30	338	Unsuccessful Exploration & Dev. Costs			
31					
32	**Total Production & Gathering Plant**				
33					
34	Products Extraction Plant				
35					
36	340	Land & Land Rights			
37	341	Structures & Improvements			
38	342	Extraction & Refining Equipment			
39	343	Pipe Lines		NOT	
40	344	Extracted Products Storage Equipment		APPLICABLE	
41	345	Compressor Equipment			
42	346	Gas Measuring & Regulating Equipment			
43	347	Other Equipment			
44					
45	**Total Products Extraction Plant**				
46					
47	**TOTAL Production Plant**				

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2001

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Natural Gas Storage and Processing Plant**			
3				
4	Underground Storage Plant			
5				
6	350.1 Land			
7	350.2 Rights-of-Way			
8	351 Structures & Improvements			
9	352 Wells			
10	352.1 Storage Leaseholds & Rights			
11	352.2 Reservoirs		NOT	
12	352.3 Non-Recoverable Natural Gas		APPLICABLE	
13	353 Lines			
14	354 Compressor Station Equipment			
15	355 Measuring & Regulating Equipment			
16	356 Purification Equipment			
17	357 Other Equipment			
18				
19	**Total Underground Storage Plant**			
20				
21	Other Storage Plant			
22				
23	360 Land & Land Rights			
24	361 Structures & Improvements			
25	362 Gas Holders			
26	363 Purification Equipment			
27	363.1 Liquification Equipment		NOT	
28	363.2 Vaporizing Equipment		APPLICABLE	
29	363.3 Compressor Equipment			
30	363.4 Measuring & Regulating Equipment			
31	363.5 Other Equipment			
32				
33	**Total Other Storage Plant**			
34				
35	**TOTAL Natural Gas Storage and Processing Plant**			
36				
37	**Transmission Plant**			
38				
39	365.1 Land & Land Rights			
40	365.2 Rights-of-Way			
41	366 Structures & Improvements			
42	367 Mains		NOT	
43	368 Compressor Station Equipment		APPLICABLE	
44	369 Measuring & Reg. Station Equipment			
45	370 Communication Equipment			
46	371 Other Equipment			
47				
48	**TOTAL Transmission Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2001

	Account Number & Title		Last Year	This Year	% Change
1					
2	**Distribution Plant**				
3					
4	374	Land & Land Rights	$34,947	$34,899	-0.14%
5	375	Structures & Improvements	190,593	190,307	-0.15%
6	376	Mains	20,389,742	20,952,392	2.76%
7	377	Compressor Station Equipment			
8	378	Meas. & Reg. Station Equipment-General	536,710	536,779	0.01%
9	379	Meas. & Reg. Station Equipment-City Gate	129,124	129,124	
10	380	Services	10,533,388	10,930,674	3.77%
11	381	Meters	9,589,090	10,041,174	4.71%
12	382	Meter Installations			
13	383	House Regulators	1,379,530	1,412,177	2.37%
14	384	House Regulator Installations			
15	385	Industrial Meas. & Reg. Station Equipment	112,646	112,646	
16	386	Other Prop. on Customers' Premises 1/	161,799	161,799	
17	387	Other Equipment	835,048	861,735	3.20%
18					
19	**TOTAL Distribution Plant**		$43,892,617	$45,363,706	3.35%
20					
21	**General Plant**				
22					
23	389	Land & Land Rights	$26,744	$26,744	
24	390	Structures & Improvements	299,252	299,252	
25	391	Office Furniture & Equipment	258,007	210,592	-18.38%
26	392	Transportation Equipment	1,834,625	1,923,223	4.83%
27	393	Stores Equipment	48,508	48,508	
28	394	Tools, Shop & Garage Equipment	886,145	919,305	3.74%
29	395	Laboratory Equipment	97,411	88,913	-8.72%
30	396	Power Operated Equipment	1,179,910	1,312,169	11.21%
31	397	Communication Equipment	349,358	354,424	1.45%
32	398	Miscellaneous Equipment	44,354	43,357	-2.25%
33	399	Other Tangible Property			
34					
35	**TOTAL General Plant**		$5,024,314	$5,226,487	4.02%
36					
37	**Common Plant**				
38					
39	389	Land & Land Rights	$181,506	$167,937	-7.48%
40	390	Structures & Improvements	2,227,673	2,104,655	-5.52%
41	391	Office Furniture & Equipment	1,078,638	1,012,162	-6.16%
42	392	Transportation Equipment	619,979	644,544	3.96%
43	393	Stores Equipment	9,191	9,287	1.04%
44	394	Tools, Shop & Garage Equipment	131,638	144,828	10.02%
45	396	Power Operated Equipment	13,890	13,626	-1.90%
46	397	Communication Equipment	491,017	508,293	3.52%
47	398	Miscellaneous Equipment	63,652	65,288	2.57%
48					
49	**TOTAL Common Plant**		$4,817,184	$4,670,620	-3.04%
50					
51	**TOTAL Gas Plant in Service**		$55,166,904	$56,786,671	2.94%

1/ Includes gas plant leased to others.

MONTANA DEPRECIATION SUMMARY

Year: 2001

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1	Production & Gathering				
2	Products Extraction				
3	Underground Storage				
4	Other Storage				
5	Transmission				
6	Distribution	$45,363,706	$27,809,866	$29,164,510	3.97%
7	General	5,285,069	2,477,005	2,455,417	1.56%
8	Common	6,137,896	2,244,321	2,471,280	5.69%
9	**TOTAL**	$56,786,671	$32,531,192	$34,091,207	3.93%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock			
3	152 Fuel Stock Expenses - Undistributed			
4	153 Residuals & Extracted Products			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)			
9	Transmission Plant (Estimated)			
10	Distribution Plant (Estimated)	$338,936	$339,713	0.23%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	163 Stores Expense Undistributed			
15				
16	**TOTAL Materials & Supplies**	$338,936	$339,713	0.23%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	D95.7.90			
2	Order Number	5856b			
3					
4	Common Equity		44.810%	12.000%	5.377%
5	Preferred Stock		1.810%	4.653%	0.084%
6	Long Term Debt		53.390%	10.212%	5.452%
7	Other				
8	**TOTAL**				10.913%
9					
10	Actual at Year End				
11					
12	Common Equity		50.800%	12.000%	6.096%
13	Preferred Stock		5.388%	4.628%	0.249%
14	Long Term Debt		43.812%	9.270%	4.061%
15	Other				
16	**TOTAL**		100.000%		10.406%

STATEMENT OF CASH FLOWS

Year: 2001

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	**Cash Flows from Operating Activities:**			
4	Net Income	$111,028,298	$155,848,507	40.37%
5	Depreciation	27,513,912	28,824,072	4.76%
6	Amortization	1,528,891	1,434,400	-6.18%
7	Deferred Income Taxes - Net	(768,308)	(11,341,055)	1376.11%
8	Investment Tax Credit Adjustments - Net	(852,655)	(731,288)	-14.23%
9	Change in Operating Receivables - Net	(24,602,540)	25,805,961	204.89%
10	Change in Materials, Supplies & Inventories - Net	4,236,915	(19,266,734)	-554.73%
11	Change in Operating Payables & Accrued Liabilities - Net	22,734,416	(17,232,734)	-175.80%
12	Change in Other Regulatory Assets	1,165,973	368,020	-68.44%
13	Change in Other Regulatory Liabilities	175,124	900,865	414.42%
14	Allowance for Funds Used During Construction (AFUDC)	(157,410)	(185,066)	17.57%
15	Change in Other Assets & Liabilities - Net	(16,394,017)	44,089,298	368.94%
16	Less Undistributed Earnings from Subsidiary Companies	(87,788,729)	(135,692,353)	54.57%
17	Other Operating Activities (explained on attached page)			
18	**Net Cash Provided by/(Used in) Operating Activities**	$37,819,870	$72,821,893	92.55%
19				
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	($33,966,186)	($30,174,257)	-11.16%
23	Acquisition of Other Noncurrent Assets	3,468,361	(1,263,118)	-136.42%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(141,457,074)	(130,138,498)	-8.00%
26	Contributions and Advances from Affiliates	34,649,500	39,709,000	14.60%
27	Disposition of Investments in and Advances to Affiliates	3,000,000	0	-100.00%
28	Other Investing Activities: Depreciation on Nonutility Plant	10,240	11,230	9.67%
29	**Net Cash Provided by/(Used in) Investing Activities**	($134,295,159)	($121,855,643)	-9.26%
30				
31	**Cash Flows from Financing Activities:**			
32	Proceeds from Issuance of:			
33	Long-Term Debt			
34	Preferred Stock			
35	Common Stock	$154,448,288	$132,499,140	-14.21%
36	Other:			
37	Net Increase in Short-Term Debt			
38	Other: Commercial Paper			
39	Payment for Retirement of:			
40	Long-Term Debt	(303,176)	(15,543,971)	5027.05%
41	Preferred Stock	(100,000)	(100,000)	0.00%
42	Common Stock			
43	Other:			
44	Net Decrease in Short-Term Debt	(5,000,000)	(8,000,000)	60.00%
45	Dividends on Preferred Stock	(766,607)	(761,507)	-0.67%
46	Dividends on Common Stock	(53,182,971)	(61,094,016)	14.88%
47	Other Financing Activities (explained on attached page)			
48	**Net Cash Provided by (Used in) Financing Activities**	$95,095,534	$46,999,646	-50.58%
49				
50	**Net Increase/(Decrease) in Cash and Cash Equivalents**	($1,379,755)	($2,034,104)	47.43%
51	**Cash and Cash Equivalents at Beginning of Year**	$8,468,450	$7,088,695	-16.29%
52	**Cash and Cash Equivalents at End of Year**	$7,088,695	$5,054,591	-28.70%

LONG TERM DEBT

Year: 2001

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost % 1/
1	8.25 % Secured MTN, Series A	04/92	04/07	$30,000,000	$26,111,796	$30,000,000	8.25%	$3,053,100	10.18%
2	8.60 % Secured MTN, Series A	04/92	04/12	35,000,000	28,906,532	35,000,000	8.60%	3,857,000	11.02%
3	6.52 % Secured MTN, Series A	09/97	10/04	15,000,000	14,082,923	15,000,000	6.52%	1,171,650	7.81%
4	6.71 % Secured MTN, Series A	09/97	10/09	15,000,000	13,488,404	15,000,000	6.71%	1,229,250	8.20%
5	5.83 % Secured MTN, Series A	09/98	10/08	15,000,000	14,813,914	15,000,000	5.83%	912,900	6.09%
6	Grant County 6.20 % PCN	03/74	03/04	5,600,000	5,427,042	2,500,000	6.20%	163,900	6.56%
7	Mercer County 6.65 % 2/	06/92	06/22	15,000,000	14,061,276	15,000,000	6.65%	1,093,200	7.29%
8	Richland County 6.65 % 2/	06/92	06/22	3,250,000	3,063,677	3,250,000	6.65%	235,398	7.24%
9	Morton County 6.65 % 2/	06/92	06/22	2,600,000	2,420,986	2,600,000	6.65%	190,944	7.34%
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26	**TOTAL**			$136,450,000	$122,376,550	$133,350,000		$11,907,342	8.93%

1/ Includes interest expense, bond discount expense, debt issuance expense and loss on bond reacquistion and redemption.
2/ Pollution Control Refunding Revenue Bonds.

PREFERRED STOCK

Year: 2001

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price 1/	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	4.50 % Cumulative	01/51	100,000	$100	$105	$10,000,000	4.50%	$10,000,000	$450,000	4.50%
2	4.70 % Cumulative	12/55	50,000	100	102	5,000,000	4.70%	5,000,000	235,000	4.70%
3	5.10 % Cumulative	05/61	50,000	100	102	4,947,548	5.29%	1,400,000	73,990	5.29%
4										
5										
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7										
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28										
29										
30										
31										
32	**TOTAL**					$19,947,548		$16,400,000	$758,990	4.63%

1/ Plus accrued dividends.

COMMON STOCK

Year: 2001

		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share 1/	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio 2/
1									
2	.								
3									
4	January	64,937,530	$13.82						
5									
6	February	65,471,329	13.83						
7									
8	March	65,812,744	14.02	$0.50	$0.2200	56.00%	$35.76	$27.38	17.5 X
9									
10	April	67,582,395	14.63						
11									
12	May	67,597,320	14.69						
13									
14	June	67,608,520	14.93	0.64	0.2200	65.63%	40.37	31.38	13.6 X
15									
16	July	67,611,495	15.17						
17									
18	August	67,614,333	15.23						
19									
20	September	67,871,080	15.58	0.75	0.2300	69.33%	32.90	22.38	9.6 X
21									
22	October	68,722,237	15.76						
23									
24	November	68,723,118	15.66						
25									
26	December	68,805,188	15.90	0.42	0.2300	45.24%	28.30	23.00	12.3 X
27									
28									
29									
30	TOTAL Year End	67,271,989	$15.90	$2.31	$0.9000	61.04%			12.3 X

1/ Basic earnings per share.
2/ Calculated on 12 months ended using closing stock price.

MONTANA EARNED RATE OF RETURN

Year: 2001

		Description	Last Year	This Year	% Change
		Rate Base			
1					
2	101	Plant in Service	$55,166,904	$56,786,671	2.94%
3	108	(Less) Accumulated Depreciation	32,531,192	34,091,207	4.80%
4					
5		**NET Plant in Service**	$22,635,712	$22,695,464	0.26%
6					
7		CWIP in Service Pending Reclassification	$183,842	$130,729	-28.89%
8					
9		Additions			
10	154, 156	Materials & Supplies	$338,936	$339,713	0.23%
11	165	Prepayments	13,713	17,446	27.22%
12		Prepaid Demand/Commodity Charges	1,253,902	1,306,868	4.22%
13		Gas in Underground Storage	2,016,827	8,690,912	330.92%
14		Unamoritzed Gas IRP	161,123	125,416	-22.16%
15					
16		**TOTAL Additions**	$3,784,501	$10,480,355	176.93%
17					
18		Deductions			
19	190	Accumulated Deferred Income Taxes	$3,257,298	$3,338,641	2.50%
20	252	Customer Advances for Construction	276,661	176,934	-36.05%
21	255	Accumulated Def. Investment Tax Credits	270,259	258,473	-4.36%
22		Other Deductions			
23					
24		**TOTAL Deductions**	$3,804,218	$3,774,048	-0.79%
25		**TOTAL Rate Base**	$22,799,837	$29,532,500	29.53%
26					
27		**Net Earnings**	$2,502,418	$889,277	-64.46%
28					
29		**Rate of Return on Average Rate Base**	10.42%	3.40%	-67.37%
30					
31		**Rate of Return on Average Equity**	12.20%	-1.79%	-114.67%
32					
33		Major Normalizing Adjustments & Commission			
34		Ratemaking adjustments to Utility Operations 1/			
35					
36		Adjustment to Operating Revenues			
37		Weather Normalization	($67,004)	$263,679	493.53%
38		Late Payment Revenue	26,780	47,968	79.12%
39					
40		Adjustment to Operating Expenses			
41		Elimination of Promotional & Institutional Advertising	(29,055)	(34,168)	17.60%
42					
43		Total Adjustments to Operating Income	($11,169)	$345,815	3196.20%
44					
45					
46		**Adjusted Rate of Return on Average Rate Base**	10.38%	4.72%	-54.53%
47					
48		**Adjusted Rate of Return on Average Equity**	12.11%	0.81%	-93.31%

1/ Updated amounts, net of taxes.

MONTANA COMPOSITE STATISTICS

Year: 2001

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$52,967
5	107	Construction Work in Progress	98
6	114	Plant Acquisition Adjustments	
7	104	Plant Leased to Others	13
8	105	Plant Held for Future Use	
9	154, 156	Materials & Supplies	340
10		(Less):	
11	108, 111	Depreciation & Amortization Reserves	34,091
12	252	Contributions in Aid of Construction	177
13			
14		**NET BOOK COSTS**	$19,150
15			
16		Revenues & Expenses (000 Omitted)	
17			
18	400	Operating Revenues	$64,354
19			
20	403 - 407	Depreciation & Amortization Expenses	$2,232
21		Federal & State Income Taxes	407
22		Other Taxes	2,210
23		Other Operating Expenses	58,616
24		TOTAL Operating Expenses	$63,465
25			
26		Net Operating Income	$889
27			
28		Other Income	418
29		Other Deductions	1,107
30			
31		**NET INCOME**	$200
32			
33		Customers (Intrastate Only)	
34			
35		Year End Average:	
36		Residential	62,170
37		Firm General	7,588
38		Small Interruptible	37
39		Large Interruptible	5
40			
41		**TOTAL NUMBER OF CUSTOMERS**	69,800
42			
43		Other Statistics (Intrastate Only)	
44			
45		Average Annual Residential Use (Dkt))	89
46		Average Annual Residential Cost per (Dkt) ($) * 1/	$5.22
		* Avg annual cost = [(cost per Dkt x annual use) +	
47		(mo. svc chrg x 12)]/annual use	
48		Average Residential Monthly Bill	$56.64
49		Gross Plant per Customer	$759

1/ Reflects cost per dk effective December 1, 2001.

MONTANA CUSTOMER INFORMATION

Year: 2001

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Belfry	219	138	21		159
2	Billings	89,847	38,989	3,702		42,691
3	Bridger	745	404	67		471
4	Crow Agency	1,552	297	64		361
5	Edgar	Not Available	101	8		109
6	Fromberg	486	270	24		294
7	Hardin	3,384	1,251	194		1,445
8	Joliet	575	343	40		383
9	Laurel	6,255	3,254	261		3,515
10	Park City	870	462	22		484
11	Pryor	628	82	12		94
12	Rockvale	Not Available	58	4		62
13	Silesia	Not Available	32	2		34
14	Warren	Not Available		1		1
15	Alzada	Not Available	7	6		13
16	Baker	1,695	751	173		924
17	Carlyle	Not Available	8	1		9
18	Fort Peck	240	124	10		134
19	Fairview	709	346	50		396
20	Forsyth	1,944	874	144		1,018
21	Frazer	452	95	14		109
22	Glasgow	3,253	1,646	287		1,933
23	Glendive	4,729	2,974	407		3,381
24	Hinsdale	Not Available	114	17		131
25	Ismay	26	10	4		14
26	Malta	2,120	999	199		1,198
27	Miles City	8,487	3,866	512		4,378
28	Nashua	325	185	20		205
29	Poplar	911	864	127		991
30	Richey	189	120	24		144
31	Rosebud	Not Available	47	6		53
32	Saco	224	44	6		50
33	Savage	Not Available	145	15		160
34	Sidney	4,774	2,241	387		2,628
35	Terry	611	315	63		378
36	St. Marie	183	133	9		142
37	Wibaux	567	217	52		269
38	Whitewater	Not Available	37	9		46
39	Wolf Point	2,663	1,405	203		1,608
40	MT Oil Fields	Not Available	2	3		5
41	**TOTAL Montana Customers**	138,663	63,250	7,170		70,420

1/ 2000 Census.

MONTANA EMPLOYEE COUNTS 1/

Year: 2001

	Department	Year Beginning	Year End	Average
1	Electric	22	20	21
2	Gas	40	43 (3)	42 (2)
3	Accounting	23	21 (1)	22 (1)
4	Marketing/Communications	6	5	5
5	Management	7	6	7
6	Power	26	26	26
7	Service 2/	54 (5)	59 (2)	56 (3)
8				
9				
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41				
42	**TOTAL Montana Employees**	178 (5)	180 (6)	179 (6)

1/ Parentheses denotes part-time.
2/ Reflects service employees such as meter readers, service dispatchers and servicemen.

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)

Year: 2002

	Project Description	Total Company	Total Montana	
1	Projects>$1,000,000			
2				
3	Common-General			
4	Develop Geospacial Enterprise Management System	$1,754,047	$451,683	1/
5				
6	Electric-Steam			
7	Install precipitator control system-Big Stone	1,193,183	295,850	1/
8	Power Plant			
9				
10				
11				
12	Other Projects<$1,000,000			
13				
14	Electric			
15	Production	$6,164,086	$1,528,350	1/
16	Transmission:			
17	Integrated	1,501,554	318,610	1/
18	Direct	321,584	33,166	2/
19	Distribution	6,097,132	862,806	2/
20	General	1,459,229	229,691	2/
22	Common:			
23	General Office	1,762,292	408,780	1/
24	Other Direct	584,762	160,183	2/
25	Total Electric	$17,890,639	$3,541,586	
26				
27	Gas			
28	Distribution	$6,211,370	$2,032,007	2/
29	General	1,212,371	415,554	2/
30	Common:			
31	General Office	1,089,313	290,343	1/
32	Other Direct	276,526	128,164	2/
33	Total Gas	$8,789,580	$2,866,068	
34				
35				
36				
37				
38				
39				
40				
41				
42				
43	TOTAL	$29,627,449	$7,155,187	

1/ Allocated to Montana.

2/ Directly assigned to Montana.

Company Name: Montana-Dakota Utilities Co.

TRANSMISSION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2001

	Total Company			
		Peak Day of Month	Peak Day Volumes Mcf or Dkt	Total Monthly Volumes Mcf or Dkt
1	January			
2	February			
3	March			
4	April			
5	May			
6	June	**NOT APPLICABLE**		
7	July			
8	August			
9	September			
10	October			
11	November			
12	December			
13	**TOTAL**			

	Montana			
		Peak Day of Month	Peak Day Volumes Mcf or Dkt	Total Monthly Volumes Mcf or Dkt
14	January			
15	February			
16	March			
17	April			
18	May			
19	June	**NOT APPLICABLE**		
20	July			
21	August			
22	September			
23	October			
24	November			
25	December			
26	**TOTAL**			

DISTRIBUTION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2001

	Total Company			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
1	January	16	240,160	6,487,364
2	February	8	277,215	6,594,748
3	March	23	189,834	4,817,062
4	April	16	152,525	3,253,631
5	May	6	82,055	1,926,170
6	June	4	72,055	1,654,013
7	July	31	60,932	1,495,657
8	August	1	58,907	1,477,435
9	September	24	72,183	1,688,088
10	October	24	170,341	3,538,585
11	November	27	232,942	4,476,806
12	December	31	261,196	6,311,197
13	**TOTAL**			43,720,756

	Montana			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
14	January	16	69,633	1,915,728
15	February	8	82,710	1,892,648
16	March	14	55,756	1,437,705
17	April	4	42,007	895,581
18	May	2	23,792	466,554
19	June	25	21,385	518,962
20	July	31	25,750	514,089
21	August	7	25,063	496,372
22	September	26	28,215	565,855
23	October	24	50,925	1,198,777
24	November	27	74,883	1,616,924
25	December	31	84,418	2,051,785
26	**TOTAL**			13,570,980

STORAGE SYSTEM - TOTAL COMPANY & MONTANA

Year: 2001

		Total Company						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
1	January	1	16	99	105,444	561	2,151,724	
2	February	19	8	1,213	138,049	9,185	2,751,424	
3	March	29	23	5,929	58,380	45,617	841,958	
4	April	27	15	67,892	22,582	680,017	159,994	
5	May	22	20	83,990	259	1,928,262	1,148	
6	June	23	28	74,693	300	1,928,222	1,140	
7	July	4	17	80,406	323	2,248,848	2,084	
8	August	3	4	78,215	352	2,248,631	1,585	
9	September	4	12	80,753	332	2,105,651	1,634	
10	October	2	24	34,648	48,755	367,451	249,271	
11	November	16	27	24,015	99,929	238,231	685,231	
12	December	12	31	1,073	135,850	4,411	2,453,413	
13	**TOTAL**					11,805,087	9,300,606	

		Montana						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
14	January							
15	February							
16	March							
17	April							
18	May							
19	June	NOT AVAILABLE						
20	July							
21	August							
22	September							
23	October							
24	November							
25	December							
26	**TOTAL**							

SOURCES OF GAS SUPPLY

Year: 2001

	Name of Supplier 1/	Last Year Volumes Dkt	This Year Volumes Dkt	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2					
3					
4					
5					
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24					
25					
26					
27					
28					
29	1/ Supplier information is proprietary and confidential.				
30					
31					
32					
33	**Total Gas Supply Volumes**	32,149,990	35,169,182	$3.262	$3.468

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 34

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2001

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings **(Mcf or Dkt)**	Achieved Savings **(Mcf or Dkt)**	Difference
1							
2	NONE						
3							
4							
5							
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30							
31							
32	**TOTAL**						

MONTANA CONSUMPTION AND REVENUES

Year: 2001

	Sales of Gas	Operating Revenues		DK Sold		Avg. No. of Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	$42,258,645	$36,482,551	5,555,748	5,780,444	62,170	61,864
2	Firm General	24,776,761	21,118,367	3,329,228	3,449,256	7,588	7,557
3	Small Interruptible	429,798	423,462	73,969	70,903	4	4
4	Large Interruptible	298		10			
5							
6							
7							
8							
9							
10							
11	**TOTAL**	$67,465,502	$58,024,380	8,958,955	9,300,603	69,762	69,425
12							
13							
14		**Operating Revenues**		**BCF Transported**		**Avg. No. of Customers**	
15							
16		Current	Previous	Current	Previous	Current	Previous
17	**Transportation of Gas**	Year	Year	Year	Year	Year	Year
18							
19	Utilities						
20	Small Interruptible	$497,120	$454,683	0.8	0.8	33	32
21	Large Interruptible	596,858	554,613	3.9	4.0	5	5
22	Firm	12,378	12,438				
23							
24	**TOTAL**	$1,106,356	$1,021,734	4.7	4.8	38	37